



DIVISION OF ENVIRONMENTAL QUALITY

DRAFT OPERATING AIR PERMIT

PERMIT NUMBER: 0449-AOP-R19

IS ISSUED TO:

Entergy Arkansas, LLC - Independence Plant
555 Point Ferry Road
Newark, AR 72562
Independence County
AFIN: 32-00042

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:

AND

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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Appendix K: 40 C.F.R. § 60, Subpart JJJJ - *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*

Appendix L: 40 C.F.R. § 97, Subpart BBBB — *TR NO_x Ozone Season Trading Program*

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

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SECTION I: FACILITY INFORMATION

PERMITTEE: Entergy Arkansas, LLC - Independence Plant

AFIN: 32-00042

PERMIT NUMBER: 0449-AOP-R19

FACILITY ADDRESS: 555 Point Ferry Road
Newark, AR 72562

MAILING ADDRESS: 555 Point Ferry Road
Newark, AR 72562

COUNTY: Independence County

CONTACT NAME: Anthony Wilson

CONTACT POSITION: Senior Lead Environmental Analyst

TELEPHONE NUMBER: (870) 698-4534

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UTM North South (Y): Zone 15: 3949363.54 m

UTM East West (X): Zone 15: 643704.53 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Entergy Arkansas, LLC - Independence (AFIN: 32-00042) located near Newark, Arkansas is a two-unit electric generating station which generates electric energy for sale. Entergy Services, LLC on behalf of Entergy Arkansas, LLC (collectively “Entergy”) submitted a Title V application to renew the Title V Operating Air Permit and Acid Rain Permit for the Independence Plant.

In addition to the request to renew the current Title V permit for the site, the applicant requested the following changes:

- The ability to operate an additional coal yard dozer by proposing the combined limit of all coal yard dozer operation be increased from 12,000 hours per consecutive twelve-month period to 15,000 hours per consecutive twelve-month period.
- Removal of the compliance assurance monitoring (CAM) plan for SN-01 and SN-02 due to the exemption under 40 CFR 64.2(b)(1)(i). The exemption states that requirements of CAM shall not apply to emission limitations or standards proposed by the Administrator after November 15, 1990, pursuant to section 111 or 112 of the Act. NSPS Subpart D establishes emission limits for Particulate Matter (PM) and has its own monitoring requirements utilizing PM CEMS; therefore, the site should not also be subject to CAM.
- Revise NSPS Subpart D and Opacity specific conditions for SN-01 and SN-02. Independence currently demonstrates compliance with applicable Opacity standards using a COMS pursuant to 60.45(a). Section 60.45(b)(5) states, in pertinent part, that “[f]or affected facilities using a PM CEMS... a COMS is not required.” Additionally, 60.45(b)(7) requires that when a facility elects to demonstrate compliance with 60.42 by monitoring PM emissions as specified under 60.45(b)(5), a performance test using Method 9 must be conducted “within 45 days after stopping use of an existing COMS.”
- This change affects specific conditions with regards to applicable Opacity limits for SN-01 and SN-02, for the following conditions 4e, 4j, 12, 14, 30, and 31.

Permitted emissions changing by 3.4 tpy PM₁₀ to 20.5 tpy PM for SCN-06C Storage Pile and Haul Road Emissions. The Facility total PM₁₀ emissions would change by 19.0 tpy PM and 3.5 tpy PM₁₀.

Process Description

Independence Steam Electric Station operates two identical coal-fired units (Units 1 and 2) with a total capacity of approximately 1,780 megawatts (MW). Electricity is produced using coal as the primary fuel and No. 2 fuel oil or biodiesel as the start-up fuel in both boilers. The boilers produce steam which is used to drive turbines that turn the electric generators.

Operating Scenario 1 (AOS1) occurs when the boilers are firing coal, and Operating Scenario 2 (AOS2) occurs when the boilers are firing No. 2 fuel oil or biodiesel.

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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-16 and SN17) which obtain makeup water from the White River and from the capture of site drainage. Unit 1 exhausts through SN-01, and Unit 2 exhausts through SN-02.

Both SN-01 and SN-02 are classified as existing units subject to NESHAP Subpart UUUUU, also known as the Mercury and Air Toxics Standard (MATS). In order to comply with the MATS rule, activated carbon injection (ACI) systems are used on each unit. These systems either utilize a halogenated activated carbon or a non-halogenated activated carbon. When a nonhalogenated activated carbon is used, the ACI system is coupled with an additional treatment of either an aqueous or a powdered halide product. Any halogenated activated carbon or halide product used at the facility utilizes non-HAP materials. The purpose of the halogenated activated carbon or halide product is to oxidize elemental mercury which increases the mercury capture efficiency of the activated carbon for units which burn low-chlorine coals such as those typically combusted at SN-01 and SN-02.

During both operating scenarios, emissions from the boilers include sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter (PM). The emission levels for each of these are governed by federal and state emission and ambient air regulations. In-stack monitoring is designed to meet the requirements of Acid Rain (40 CFR § 75) and New Source Performance Standards (NSPS) (40 CFR § 60). Oxides of nitrogen (NO_x) must meet NSPS and acid rain requirements. Both boilers operate with NO_x emission controls, LowNO_x Burners and Separated Overfire Air Systems, which were installed in 2017 in order to assist the facility in meeting its obligations under the Cross-State Air Pollution Rule (CSAPR). Additionally, emissions of SO₂ and PM are subject to controls and emission limits under the Prevention of Significant Deterioration (PSD) program under 40 CFR § 52. These emissions are controlled by sulfur limitations in the fuel and an electrostatic precipitator, respectively.

The Independence Plant operates a 183.6 MMBtu/hr auxiliary boiler (SN-05) which combusts No. 2 fuel oil or biodiesel to provide steam for startup and shutdown activities. This unit was installed in 1978, and no emission controls are associated with this source. SN-05 is subject to regulation under the provisions of the Industrial Boiler MACT (40 C.F.R. § 63 Subpart DDDDD).

Other major plant components include facilities for storage and handling of coal and disposal of ash, a switchyard, sandblasting, water treatment, surge and other ponds, intake and discharge structures, emergency generators, an emergency fire pump, and fuel storage tanks for gasoline, No. 2 fuel oil, and biodiesel.

Other emissions-producing activities at the Independence Plant are all in support of the primary process at the facility, which is the production of electricity as described above. These other emissions producing activities are necessary to maintain the power plant equipment and systems. These activities include, but are not limited to, painting, welding, boiler cleaning and the use of temporary combustion devices to drive equipment during outages. Many of these maintenance activities are conducted by outside contractors using equipment owned by the contractors.

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Furthermore, many of these maintenance activities are classified as insignificant activities and are listed in Section VII of the permit.

Entergy's telecommunications support group owns and operates a small 30 kW emergency generator (SN-23) at the Independence plant site. This emergency generator is powered by a propane-fired spark-ignition 4-stroke engine and 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.

Primary Operating Scenario

In the primary operating scenario (AOS1), coal is combusted in the main boilers. During AOS1, particulates are controlled to meet NSPS and MATS requirements by use of cold side electrostatic precipitators and sulfur oxide emissions meet NSPS, PSD, and acid rain requirements by the combustion of low sulfur coal. Emissions of mercury are controlled to meet MATS requirements through the use of an activated carbon injection (ACI) system.

Sub-bituminous or bituminous coal is delivered by rail. 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 a scraper and bulldozers.

There are numerous transfer points, conveyors, towers, and connections associated with coal and its handling. Dust suppression is accomplished with chemical foam and water sprays.

Alternative Operating Scenario

In the alternative operating scenario (AOS2), No. 2 fuel oil or biodiesel is combusted in the main boilers, and the electrostatic precipitators are not employed.

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 – <i>Prevention of Significant Deterioration of Air Quality (PSD)</i>
40 C.F.R. § 60 – Subpart D – <i>Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971</i>
40 C.F.R. § 60 – Subpart Y – <i>Standards of Performance for Coal Preparation Plants</i>
40 C.F.R. § 61 – Subpart M – <i>National Emissions Standard for Asbestos</i>
40 C.F.R. § 63 – Subpart ZZZZ – <i>National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (effective date May 3, 2013)</i>
40 C.F.R. § 63 – Subpart DDDDD – <i>National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters</i>
40 C.F.R. § 63 – Subpart UUUUU – <i>National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units</i>
40 C.F.R. § 72 – Subpart A-D – <i>Permits Regulation (Acid Rain)</i>
40 C.F.R. § 73 – Subpart B – <i>Sulfur Dioxide Allowance System</i>
40 C.F.R. § 75 – <i>Continuous Emission Monitoring</i>
40 C.F.R. § 76 – <i>Acid Rain Nitrogen Oxide Emission Reduction Program</i>
40 C.F.R. § 77 – <i>Excess Emissions</i>
40 C.F.R. § 82 – <i>Protection of Stratospheric Ozone</i>
40 C.F.R. § 97 – Subpart BBBB – <i>TR NO_x Ozone Season Trading Program</i>
40 C.F.R. § 60 – Subpart JJJJ – <i>Standards of Performance for Stationary Spark Ignition Internal Combustion Engines</i>

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	1,502.5	6,231.4
		PM ₁₀	1,387.0	5,986.7
		PM _{2.5}	See Note****	See Note****
		SO ₂	16,282.3	71,299.8
		VOC	136.7	331.0
		CO	2671.7	11,538.6
		NO _x	12,252.2	53,536.40
		Lead	0.47	1.95
HAPs		Total HAP***	257.27	931.38
		Cyanide	2.64	11.5
		Hydrogen Chloride	84	184
		Hydrogen Fluoride	157.5	689.86
		Methylene Chloride	0.32	1.34
Air Contaminants ***		H ₂ SO ₄	17.08	74.79
		N ₂ O	61.65	270.07
SN-01 (C1)	Unit 1 Boiler – Coal Fired	PM	661.9	2,899.1
		PM ₁₀	661.9	2,899.1
		SO ₂	8,091.0	35,438.6
		VOC	35.0	153.3
		CO	1305.0	5,715.9
		NO _x	6,090.0	26,674.2
		Lead	0.23	0.97
		Total HAP	127.17	465.02
		Cyanide	1.32	5.75
		Hydrogen Chloride	42.00	92.00
		Hydrogen Fluoride	78.75	344.93
		Methylene Chloride	0.16	0.67
		H ₂ SO ₄	7.81	34.20
		N ₂ O	30.7	134.5

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-02 (C2)	Unit 2 Boiler – Coal Fired	PM	661.9	2,899.1
		PM ₁₀	661.9	2,899.1
		SO ₂	8,091.0	35,438.6
		VOC	35.0	153.3
		CO	1305.0	5,715.9
		NO _x	6,090.0	26,674.2
		Lead	0.23	0.97
		Total HAP	127.17	465.02
		Cyanide	1.32	5.75
		Hydrogen Chloride	42.00	92.00
		Hydrogen Fluoride	78.75	344.93
		Methylene Chloride	0.16	0.67
		H ₂ SO ₄	7.81	34.20
		N ₂ O	30.7	134.5
SN-01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Biodiesel Fired	PM	24.1	105.5
		PM ₁₀	16.8	73.5
		SO ₂	518.3	2,270.0
		VOC	1.9	8.1
		CO	150.0	657.0
		NO _x	175.2	767.4
		Lead	0.01	0.04
		Total HAP	0.48	2.07
		H ₂ SO ₄	8.00	34.80
		N ₂ O	1.34	5.83
SN-02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Biodiesel Fired	PM	24.1	105.6
		PM ₁₀	16.8	73.5
		SO ₂	518.3	2,270.0
		VOC	1.9	8.1
		CO	150.0	657.0
		NO _x	175.2	767.4
		Lead	0.01	0.04
		Total HAP	0.48	2.07
		H ₂ SO ₄	8.00	34.80
		N ₂ O	1.34	5.83
SN-03 (M1)	Rail Car Rotary Dumper	PM	0.1	0.1
		PM ₁₀	0.1	0.1
		VOC	1.3	1.1
SN-04 (M30-31)	Fly Ash Silos (2) with Fabric Filters	PM	0.1	0.1
		PM ₁₀	0.1	0.1

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-05 (C3)	Auxiliary Boiler Scenario 1: Limited-use boiler emissions	PM	4.5	2.0
		PM ₁₀	4.5	2.0
		SO ₂	95.2	41.7
		VOC	0.4	0.2
		CO	18.7	8.2
		NO _x	32.2	14.1
		Lead	0.01	0.01
		Total HAP	0.29	0.13
		H ₂ SO ₄	1.46	0.64
		N ₂ O	0.25	0.11
SN-05 (C3)	Auxiliary Boiler Scenario 2: Liquid/Light liquid-fired boiler emissions	PM	4.5	19.4
		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
		Total HAP	0.29	1.27
		H ₂ SO ₄	1.46	6.39
		N ₂ O	0.25	1.07
SN-06A	Handling / Conveying Emissions	PM	1.1	4.6
		PM ₁₀	0.5	2.2
		VOC	1.3	1.1
SN-06B	Stacker / Reclaimer Emissions	PM	1.0	2.6
		PM ₁₀	0.5	1.2
SN-06C	Storage Pile and Haul Road Emissions	PM	156.8	346.9
		PM ₁₀	43.8	110.9
		VOC	27.4	5.0
SN-07 (T1)	Fuel Oil Storage Tank	VOC	1.5	0.6
SN-12 (T27)	Replaced with T-90 (A-3 insignificant activity)			
SN-13 (T29)	Replaced with SN-24			
SN-16 (X35)	Cooling Tower # 1	PM	5.7	24.9
		PM ₁₀	5.7	24.9
SN-17 (X36)	Cooling Tower # 2	PM	5.7	24.9
		PM ₁₀	5.7	24.9
SN-18	Degreasing Operations	VOC	8.5	12.0

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-19 (X23)	Grit Blaster	PM	1.8	7.6
		PM ₁₀	0.7	2.7
SN-20 (C4)	Emergency Diesel Generator	PM	0.6	0.7
		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 HAP	0.02	0.02
SN-21 (C5)	Emergency Diesel Fire Pump	PM	0.9	1.3
		PM ₁₀	0.9	1.3
		SO ₂	0.8	1.2
		VOC	1.0	1.5
		CO	2.7	4.0
		NO _x	12.1	18.2
		Total HAP	0.02	0.02
SN-22	Replaced with SN-23			
SN-23	Telecom Emergency Generator	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 HAP	0.04	0.01
SN-24 (T29)	Unleaded Gasoline Tank	VOC	23.0	0.4
		Total HAP	1.31	0.02

*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.

*** Total HAP includes any species listed below. Total HAP is the sum total of all reported HAP and is not the sum total of species specifically listed. Methylene Chloride is listed here for fee calculation purposes.

**** PM_{2.5} limits are source specific, if required. Not all sources have PM_{2.5} limits.

SECTION III: PERMIT HISTORY

449-A was issued to Arkansas Power & Light Company on November 1, 1977. 449-A permitted the installation of the coal-fired steam electric station near Newark on the White River. The permit established the limit of the SO₂ emission rate at 0.93 lbs/MMBtu heat input. The maximum emission rate for TSP was limited to 611 lb/hr based on the use of coal with a heat content of 8700 Btu/lb and a maximum sulfur and ash content of 0.45 percent and 8 percent, respectively on an as received basis.

PSD-AR-48 was issued by the Environmental Protection Agency (EPA) to Arkansas Power and Light Company to construct the Independence Steam Electric Station on March 30, 1978. This PSD permit limited the emission rates from the common stack of the two 800 MW coal-fired units (Units 1 and 2) to 15,510 lb/hr SO₂ and 611 lb/hr TSP based on the use of coal with a heat content of 8,700 Btu/lb and a maximum sulfur of 0.45% and a maximum ash content of 8%. Limits of 0.04 lb/106 Btu TSP and 0.93 lb/106 Btu SO₂ were also included. The EPA determined that the facility met the Best Available Control Technology (BACT) requirements for SO₂ and TSP. (The actual technology requirements were not specified in the permit.) This source was also subject to the requirements of 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, except that the maximum allowed emissions for TSP and SO₂ were 0.04 and 0.93 lb/106 Btu and 40 C.F.R. § 60 Subpart Y-Standards of Performance for Coal Preparation Plants.

449-AR-1 was issued to Arkansas Power & Light Company- Independence Steam Electric Station on April 9, 1991. In June, 1990, AP&L announced its intent to sell a percentage of power from Unit 2 to Entergy Power Incorporated (EPI). EPI is a subsidiary of Entergy Corporation. It was determined that a revised permit for the Independence facility was needed. The revised permit incorporated existing lb/106 Btu limits for particulate matter, and sulfur dioxide. The lb/hr limit for SO₂ was increased from 15,510 lb/hr to 16,182 lb/hr (8,091 lb/hr for each unit.) The lb/hr limit for TSP was increased from 611 lb/hr to 696 lb/hr (348 lb/hr for each unit.) The limits from 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, were incorporated for oxides of nitrogen and opacity. It also identified emission sources that were not addressed in the original permit application (i.e. rotary car dumper, fly ash silos) and estimated pollutant emissions from fuel oil storage facilities and air toxic emissions. The restrictions of 40 C.F.R. § 60, Subpart Y-Standards of Performance for Coal Preparation Plants were removed from the permit because the facility commenced construction before the applicable date.

0449-AOP-R0 was issued March 10, 1998 and the first operating air permit issued to Entergy-Arkansas, Inc.-Independence Steam Electric Station under Regulation 26 (Title V). There were no physical changes in the method of operation at the facility. Entergy-Arkansas, Inc. increased the CO limit for the Independence facility from 300 lb/hr (50 ppm) to 3232 lb/hr or 300 ppm hourly (100 ppm 24-hour average) to reflect the optimum range for unit operating efficiency. Modeling analysis at a 500 ppm emission rate was conducted and showed no significant impact

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to the NAAQS. In addition, a Best Achievable Control Technology review was conducted since the facility is currently subject to PSD.

Permit #449-AOP-R1 was issued July 12, 2000. In this minor modification, storage tanks SN-10 and SN-11, and the Emergency Diesel Generator (SN-08), and the Fire Pump Emergency Diesel Generator (SN-09) were moved to the insignificant activities list. Storage tank SN-15 was removed from the permit because it was no longer in existence. The fuel throughput for storage tanks SN's 12, 13, and 14 was increased. The true vapor pressure for SN-13 and SN-14 was also increased.

Permit #449-AOP-R2 was issued November 8, 2001. In this minor modification, the facility replaced the control equipment associated with the rail car rotary dumper (SN-03) and the coal emission points (SN-06) with chemical foam spray. Emissions from the use of the chemical foam spray were permitted at 2.2 tpy VOC.

Permit #449-AOP-R3 was issued on June 3, 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 diesel throughput of SN-12; move SN-14 to the insignificant activities list; increase the cooling tower circulating water flow rate (SN-16 and SN-17); increase the cooling tower total dissolved solids content (SN-16 and SN-17); permit the degreasers (SN-18) and grit blaster (SN-19) which were previously submitted as insignificant; correct the emission rate limits of SN-05 to reflect No. 2 fuel oil firing; correct the fly ash silos (SN-04) PM emission rates; specify the CO PSD limit and compliance demonstration (SN-01 and SN-02); correct the permitted annual CO emission rate (SN-01 and SN-02) to correspond with the PSD limit of 100 ppm (24-hr average); update the PM10 emission rates (SN-01, SN-02, and SN-05) to include condensable particulate matter; and correct the permitted PM emission rates (SN-01 and SN-02) to correspond with the PSD limit of 0.04 lb/MMBtu. An administrative amendment was issued on August 8, 2005 to remove the words "from northeastern Wyoming" from the process description and to remove the "-88" from ASTM D4507-88 for the fuel oil sampling condition.

Permit # 0449-AOP-R4 was issued on May 8, 2006. The permitting actions included:

- Allowing for the use of bituminous coal;
- Increasing the coal sulfur and ash contents;
- Setting the PM10 emission rate limits equal to the PM emission rate limits for SN-01 and SN-02;
- Adding Specific Condition #6;
- Revising Specific Condition #28;
- Adding Specific Condition #29;
- Adding 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 (which includes the addition of Specific Condition #41); and
- Revising the opacity limit for SN-04.

The total permitted emission rate increases associated with the permitting actions included: 1,830.8 tons per year (tpy) PM and 4,599.0 tpy PM10. These increases did not require PSD

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review because there was no physical modification to the boilers (SN-01 and SN-02) and the original PM PSD limit had not changed with the modification. The PSD limit of 0.04 lb of filterable PM per MMBtu still applied to SN-01 and SN-02.

Permit # 0449-AOP-R5 was issued on December 7, 2007. With the modification, Entergy submitted the language 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 (H₂SO₄) emissions from SN-01 and SN-02. Additionally, Entergy determined that Scenario 2 – Fuel Oil Firing, PM/PM₁₀ emissions from SN-01 and SN-02 is more accurate if 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. Also, Entergy requested the increase of the permitted annual throughput for degreasing operations and submitted calculations supporting the increased throughput. The total annual permitted emission rate increases due to the permitting action included 13.4 tons per year PM, 13.2 tpy PM₁₀, 1.6 tpy VOC, and 102.54 tpy H₂SO₄.

Permit # 0449-AOP-R6 was issued on January 12, 2009. With the modification, Entergy updated the fuel oil N₂O emissions. The N₂O annual emissions for the fuel oil fired scenario increased by 11.12 tpy. The total annual permitted emission rate increases included 0.88 tpy of N₂O. The permit modification also incorporated the facility's Clean Air Interstate Rule (CAIR) permit application.

Permit 0449-AOP-R7 was issued on April 22, 2011. With this Title V Renewal, Entergy moved the emergency diesel engine and the emergency diesel fire pump out of the Insignificant Activities list and listed them as permitted sources. The total permitted emission changes included increases of 40.3 tpy of PM₁₀, 5.7 tpy of SO₂, 4.2 tpy of VOC, 11.5 tpy of CO, and 46.7 tpy of NO_x.

Permit 0449-AOP-R8 was issued on January 21, 2015. With this modification, Entergy incorporated the 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, also referred to as the Mercury Air Toxic Standards (MATS), and accounted for the additional traffic on the roads due to deliveries of activated carbon and halide solution deliveries. Two activated carbon silos and two aqueous halide storage units were added to the insignificant activities list. The total permitted emission decreases included 132.5 tpy of PM and 26.5 tpy of PM₁₀.

Permit 0449-AOP-R9 was issued on September 14, 2015. Entergy submitted an application to incorporate applicable IB Boiler MACT requirements and revise the applicable requirements of MATS for SN-01 and SN-02. Overall, permitted emissions changed by +0.1 tpy PM/PM₁₀, - 43.9 tpy SO₂, +0.1 tpy VOC, +52.4 tpy CO, and +0.4 tpy NO_x.

Permit 0449-AOP-R10 was issued on May 19, 2016 the Title V permit was renewed with modifications to the permit. Bio-diesel was permitted for use in the emergency generators. The VOC emissions from the use of dust suppressants were permitted. An alternate PM₁₀ test

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method was approved. The CAIR provisions previously in SECTION VI were replaced with CSAPR. MATS and Boiler MACT provisions were incorporated and/or modified. Overall, permitted emissions decreased by 2.4 tpy PM, 0.8 tpy PM10, and 0.06 tpy Lead, and permitted emissions increased by 5.0 tpy VOC and 0.1 tpy CO.

Permit 0449-AOP-R11 was issued on May 16, 2017. Entergy submitted a permit application to retrofit the two units (SN-01 and SN-02) with low NOx burners and separated overfire air. Overall permitted CO emissions increased by 1,994.4 tpy.

Permit 0449-AOP-R12 was issued on December 7, 2017. Entergy submitted an administrative amendment to add one (1) new 550 gal coal yard hydraulic oil tank to the Insignificant Activities List. There were no changes to the total annual permitted emission rates.

Permit 0449-AOP-R13 was issued on July 23, 2018. Entergy submitted an administrative amendment to:

1. Add three new lube oil tanks of each 250 gallons, T87, T88, and T89 as A-2 Insignificant Activities.
2. Replace T75 thru T82, with tanks of the same volume as the old tanks and storing the same content, as A-2 Insignificant Activities.
3. Replace T25, T26, T83, T84, and T85, with tanks of the same volume as the old tanks and storing the same content as A-3 Insignificant Activities.
4. Add two economizer ash silos, M60 and M61, as A-13 Insignificant Activities.

There were no changes to the total annual permitted emission rates.

Permit 0449-AOP-R14 was issued on January 18, 2019. Entergy submitted an administrative amendment to add two powdered halide hoppers (X61) as A-13 Insignificant Activities. There were no changes to permitted emission rates.

Permit 0449-AOP-R15 was issued January 27, 2020. Entergy submitted an administrative amendment to add a Bottom Ash Bunker System (X-62) as an A-13 Insignificant Activity. There were no changes to permitted emission rates.

Permit 0449-AOP-R16 was issued on September 22, 2020. Entergy submitted multiple modifications that made the following changes:

- Minor modification replaced the existing Telecom Emergency Generator (SN-22) with a new, 64.1 hp, propane-powered Telecom Emergency Generator (SN-23).
- Added conditions for complying with Phase II Regional Haze State Implementation Plan for SN-01 and SN-02 for the SO2 limit of 0.60 lb/MMBtu
- Decreased the permitted annual HCl limits for SN-01 and SN-02 to 92.0 tpy each. The new HCl emission limits were based on NESHAP UUUUU HCl limit of 2.0E-03 lb/MMBtu instead of AP-42 HCl emission factor of 1.2 lb/ton.
- Minor modification removed a 15,000 gal diesel storage tank (SN-12) and a 2,500 gal gasoline storage tank (SN-13). Added a 2,000 gal gasoline storage tank (SN-24) and a 10,000 gal diesel storage tank (T-90) (A-3 insignificant activity).

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- Updated Specific Condition #70 to provide CO test scheduling flexibility for SN-01 and SN-02.

Overall permitted emissions increased by 1.2 tpy VOC and 13.4 tpy CO and decreased by 5334.8 tpy HCl and 5334.74 tpy Total HAPs.

Permit 0449-AOP-R17 was issued on April 27, 2021. Entergy submitted an application to renew the Title V permit with the following modifications.

- Revised specific conditions (SN-01 and SN-02) for 40 C.F.R. § 63 Subpart UUUUU which was updated September 2020.
- Revised CO limits for Unit 1 and 2 Boilers (SN-01 and SN-02) which operate with Low-NOx Burners and Separated Overfire Air Systems.
- Added one coal yard dozer (SN-06C) and increased dozer operation from 9,000 hrs to 12,000 hrs per year.
- Reduced Fuel Oil Storage Tank (SN-07) storage capacity from 3,360,000 gallons to 596,750 gallons.
- Revised HAP and VOC emissions for Unleaded Gasoline Tank (SN-24) based on corrected tank parameters.
- Updated the Insignificant Activities List – removed two (2) Fly Ash Lube Oil Tanks (T81, T82), added Turbine Lube Oil Tank (T91); added Portable Diesel Tank (T92); removed Oily Water Separator Fuel Oil Tank (W5).
- Corrected emissions due to calculation errors for SN-01/SN-02 (Total HAP, H₂SO₄), SN-05 (Lead, Total HAP), SN-6B (PM, PM₁₀), SN-20 (Total HAP) and SN-21 (Total HAP).
- An Administrative Amendment added a Fly Ash Railcar Transloader to the A-13 Insignificant Activities List.

Overall permitted emissions increased by 18.7 tpy PM and 4.1 tpy PM₁₀. Emissions decreased by 2.6 tpy VOC, 0.2 tpy CO, 0.09 tpy Lead, 34.14 tpy H₂SO₄ and 100.20 tpy Total HAPs.

Permit 0449-AOP-R18 was issued on January 17th, 2023. Entergy submitted an application to the Title V permit with the following modifications.

- Revise Specific Conditions #7 and #8 to incorporate the obligations reached in the Settlement Agreement between Entergy, Sierra Club, and the National Parks Conservation Association as well as to satisfy Regional Haze requirements.
- Revise emission limits for SN-07 and SN-24 reflecting updates to AP-42 emission factors.
- Include kerosene-fired space heaters into the facility's Insignificant Activities list.

As a result of this modification, emissions of VOC decreased by 0.6 tpy.

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. Both boilers were installed in 1978. Unit 1 (SN-01) was placed into operation in 1983 and Unit 2 (SN-02) was placed into operation in 1985. The boilers use sub-bituminous coal as their primary fuel and No. 2 fuel oil or Bio-diesel as the start-up fuel. 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. 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.

A PSD permit was issued by the EPA in 1978 for the Independence facility. The facility underwent PSD review for SO₂ and TSP. The limits of 0.04 lb/10⁶ Btu TSP and 0.93 lb/10⁶ Btu SO₂ are still in effect. A PSD permit for CO was issued by the Division of Environmental Quality in 1998. These limits are specified in the Specific Conditions section for these sources.

Particulate emissions from SN-01 and SN-02 are controlled with electrostatic precipitators. NSPS emissions standards for particulate matter are 0.1 lb/MMBtu and a maximum opacity of 20 percent. However, the more stringent PSD emission limitation of 0.04 lb/MMBtu is in effect for this facility. A continuous opacity monitor records opacity emissions. A particulate matter continuous emissions monitoring system (PM CEMS) records particulate matter emissions. Opacity emissions are able to be recorded through visual emissions checks and EPA Method 9 certified observations or a continuous opacity monitor, depending on how the facility elects to demonstrate compliance.

Permit 0449-AOP-R11 was issued in 2017 that retrofitted SN-01 and SN-02 with low NO_x burners and separated overfire air. PSD emission limitation of 0.15 lb CO/MMBtu when burning coal, No. 2 fuel oil or bio diesel is in effect for this facility.

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. However, the more stringent PSD emission limitation of 0.93 lb/MMBtu is in effect for this facility. As incorporated by the Phase II Regional Haze State Implementation Plan, an emission limit of 0.60 lb/MMBtu based on a 30-boiler-operating-day averaging period becomes effective August 7, 2021. A continuous emissions monitoring system measures sulfur dioxide emissions. Continuous emissions monitoring systems also measure CO₂ emissions and NO_x emissions under Acid Rain requirements (40 C.F.R. § 75).

SN-05 is a 183 million Btu per hour boiler. It was installed in 1978. This Auxiliary Boiler combusts No. 2 fuel or Bio-diesel in order to provide steam for unit start-up and shut-down activities. There are no control devices associated with this source.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following tables.
 - a. The permittee shall not exceed the emission rates in the following table when operating under Scenario I: Coal Firing, coal and oil firing and the first hour when switching from Scenario I to Scenario II. [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 Operating Scenario 1	PM ₁₀	662.0*	2,899.6
		SO ₂	8,091.0	35,438.6
		VOC	35.0	153.3
		CO	1305.0	5715.9
		NO _x	6,090.0	26,674.2
		Lead	0.23	0.97
SN-02 (C2)	Unit 2 Boiler – Coal Fired Operating Scenario 1	PM ₁₀	662.0*	2,899.6
		SO ₂	8,091.0	35,438.6
		VOC	35.0	153.3
		CO	1305.0	5715.9
		NO _x	6,090.0	26,674.2
		Lead	0.23	0.97

*Note: This lb/hr limit is based on 348 lb/hr filterable PM₁₀ and 314 lb/hr condensable PM₁₀. See Specific Condition # 2.

2. The permittee shall not exceed the maximum PSD emission rates set forth in the following table, when operating under Scenario I: Coal Firing. [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 Operating Scenario 1	PM	348.0*	1,524.3*
		SO ₂	8,091.0	35,438.6
		CO	1305.0	5715.9
SN-02 (C2)	Unit 2 Boiler – Coal Fired Operating Scenario 1	PM	348.0*	1,524.3*
		SO ₂	8,091.0	35,438.6
		CO	1305.0	5715.9

*Filterable PM only as measured by US EPA Reference Method 5. See Specific Condition # 6.

3. The permittee shall not exceed the emission rates set forth in the following table, when operating under Scenario I: Coal Firing. [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 Operating Scenario 1	PM	662.0*	2,899.6
		Total HAP **	127.17	465.02
		Cyanide	1.32	5.75
		Hydrogen Chloride	42.00	92.00
		Hydrogen Fluoride	78.75	344.93
		Methylene Chloride	0.16	0.67
		H ₂ SO ₄	7.81	34.20
		N ₂ O	30.70	134.50
SN-02 (C2)	Unit 2 Boiler – Coal Fired Operating Scenario 1	PM	662.0*	2,899.6
		Total HAP **	127.17	465.02
		Cyanide	1.32	5.75
		Hydrogen Chloride	42.00	92.00
		Hydrogen Fluoride	78.75	344.93
		Methylene Chloride	0.16	0.67
		H ₂ SO ₄	7.81	34.20
		N ₂ O	30.70	134.50

* This lb/hr limit is based on 348 lb/hr filterable PM and 314 lb/hr condensable PM. See Specific Condition # 2.

** Total HAP includes any species listed below. Total HAP is the sum total of all reported HAP and is not the sum total of species specifically listed.

4. 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. A copy of Subpart D is provided in Appendix A. Applicable provisions of Subpart D, include, but are not limited to: [8 CAR § 41-204 and 40 C.F.R. § 60]
- PM emissions shall not exceed 0.1 lb/MMBtu.* [8 CAR § 41-204 and 40 C.F.R. § 60.42(a)(1)]
 - Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity and 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)]
 - SO₂ emissions shall not exceed 1.2 lb/MMBtu.** [8 CAR § 41-204 and 40 C.F.R. § 60.43(a)(2)]
 - NO_x emissions shall not exceed 0.7 lb/MMBtu. [8 CAR § 41-204 and 40 C.F.R. § 60.44(a)(3)]
 - The permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for NO_x, SO₂, and CO₂. As the facility operates a PM CEMS, a COMS is not required in accordance with §60.45(b)(5). [8 CAR § 41-204 and 40 C.F.R. § 60.45(a)]

- f. As the facility operates a PM CEMS, a COMS is not required. [8 CAR § 41-204 and 40 CFR 60.45(b)(5)]
- g. As the facility is subject to an opacity standard under §60.42 and is electing not to use a COMS in accordance with §60.45(b)(5), a performance test using Method 9 shall be conducted within 45 days after stopping use of an existing COMS and will conduct subsequent Method 9 testing according to the requirements in paragraph (b)(7) of this section. [8 CAR § 41-204 and 40 CFR 60.45(b)(7)]
- h. Excess emission and monitoring system performance reports shall be submitted to the ADEQ for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in 60.45(g)(1), (2), and (3). [8 CAR § 41-204 and 40 C.F.R. § 60.45(g)]
- i. 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)]
- j. Excess SO₂ emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO₂ 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)]
- k. 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)]
- l. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating 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)]
- m. 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. [8 CAR § 41-204 and 40 C.F.R. §40 CFR 60.45(h)]

Note these units are also subject to PSD Restrictions.

*A more stringent PSD limit of 0.04 lb PM/MMBtu is in effect for these units. (See Specific Condition # 5)

**A more stringent PSD limit of 0.93 lb SO₂/MMBtu is in effect for these units. (See Specific Condition # 5)

- 5. 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]

Source No.	Pollutant	lb/MMBtu
SN-01	PM*	0.04
	SO ₂	0.93
SN-02	PM*	0.04
	SO ₂	0.93

* Filterable PM only, as measured by US EPA Reference Method #5.
 See Specific Condition # 6.

6. The PM emission limits of Specific Condition # 5 are for filterable PM as measured by US EPA Reference Method #5. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
7. No later than December 31, 2030, Entergy Arkansas shall permanently cease the combustion of coal at Independence. [8 CAR § 41-605, 40 C.F.R. § 51.308, and 40 C.F.R. § 52 Subpart E]
8. No later than June 30, 2021, Entergy Arkansas shall ensure that emissions of SO₂ at Independence Units 1 and 2 shall not exceed 0.6 lb/MMBtu based on a 30-boiler-operating-day rolling average. [8 CAR § 41-605, 40 C.F.R. § 51.308, and 40 C.F.R. § 52 Subpart E]
9. The permittee shall maintain records which demonstrate compliance with the SO₂ emission limits set in Specific Conditions # 1, # 4, #5, and #8. These records may be used by the Division of Environmental Quality for enforcement purposes. For Specific Condition #1, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO₂ 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 Conditions #4 and # 5, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO₂ 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 of Environmental Quality personnel upon request. Records shall be submitted in accordance with General Provisions # 7 and # 8. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
10. The permittee shall maintain records which demonstrate compliance with the NO_x emission limits set in Specific Conditions #1 and # 4. These records may be used by the Division of Environmental Quality 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 #4, 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 of Environmental Quality personnel upon request. Records shall be submitted in accordance with General Provisions # 7 and # 8. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

11. 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, No. 2 fuel oil, or bio-diesel. 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 # 12. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E and 40 C.F.R. § 60.42(a)(2)]
12. The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and all particular matter, SO₂, NO_x and CO₂ emissions discharged to the atmosphere from SN-01 and SN-02 and record the output of the system. This CEMS shall comply with the Air Division's "Continuous Emission Monitoring System 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).

Except for opacity, the permittee must report all excess emissions including those excess emissions caused by startups, shutdowns, and malfunctions. For opacity, all exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction. Only those opacity exceedances that are not attributable to startup, shutdown, and malfunction will be used for calculating the percentage of compliance with the NSPS opacity limit. Opacity exceedances would not be reported under 8 CAR § 41-501 for 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 a sudden or unforeseen failure or malfunction. Shutdown ends when the unit is no longer combusting fuel and fan operation is no longer required. [8 CAR § 41-801 *et seq.*, 8 CAR § 41-603, 40 C.F.R. § 60, Subpart D, 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]

13. The permittee shall submit quarterly excess emissions and monitoring systems performance reports to the Division of Environmental Quality. The reports shall include the magnitude of excess emissions, date and time of commencement and completion of each period of excess emissions, process operating time during reporting period, date and time of each period during which the CEMS are 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. Reports shall be submitted through the Department's online ePortal system or sent to the following address [8 CAR § 41-204 and 40 C.F.R. § 60.7]:

Arkansas Energy & Environment, Division of Environmental Quality
Office of Air Quality
ATTN: Compliance Inspector Supervisor
5301 Northshore Drive
North Little Rock, AR 72118

14. The permittee shall ensure that all continuous emission monitoring systems are in operation and monitoring all unit emissions at all times that the affected unit combusts any fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. All reports shall be submitted to the ADEQ for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in §60.45(g)(1), (2), and (3).
[8 CAR § 41-603, 40 C.F.R. § 75.10, 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]
15. 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 SO₂ emission limits shall be demonstrated by compliance with Specific Condition #17. Compliance with the listed NO_x emission limits shall be demonstrated by compliance with Specific Condition #18. 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
SN-01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel Fired Operating Scenario 2	PM ₁₀	16.8	73.6
		SO ₂	518.3	2,270.0
		VOC	1.9	8.1
		CO	150.0	657.0
		NO _x	175.2	767.4
		Lead	0.01	0.04
SN-02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel Fired Operating Scenario 2	PM ₁₀	16.8	73.6
		SO ₂	518.3	2,270.0
		VOC	1.9	8.1
		CO	150.0	657.0
		NO _x	175.2	767.4
		Lead	0.01	0.04

16. 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
SN-01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel Fired Operating Scenario 2	PM	24.1	105.6
		Total HAP	0.48	2.07
		H ₂ SO ₄	8.00	34.80
		N ₂ O	1.34	5.83
SN-02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel Fired Operating Scenario 2	PM	24.1	105.6
		Total HAP	0.48	2.07
		H ₂ SO ₄	8.00	34.80
		N ₂ O	1.34	5.83

17. The permittee shall maintain records which demonstrate compliance with the SO₂ emission limits set in Specific Condition # 15 and may be used by the Division of Environmental Quality for enforcement purposes. For Specific Condition # 15, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO₂ 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 # 15. For Specific Condition # 5, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO₂ as measured by a CEMS and converted to pounds per MMBtu. These records shall be kept on site and shall be provided to Division of Environmental Quality personnel upon request. Records shall be submitted in accordance with General Provisions # 7 and # 8. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
18. The permittee shall maintain records which demonstrate compliance with the NO_x emission limits set in Specific Condition # 15 and may be used by the Division of Environmental Quality for enforcement purposes. For Specific Condition # 15, 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 # 15. These records shall be kept on site and shall be provided to Division of Environmental Quality personnel upon request. Records shall be submitted in accordance with General Provisions # 7 and # 8. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
19. The permittee may burn No. 2 Fuel Oil or Bio-diesel during startup, shutdown, and malfunction. For all other No. 2 Fuel Oil or Bio-diesel 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 of Environmental Quality. The facility submitted a request for determination on June 15, 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]

20. 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. [8 CAR § 42-601 and 40 C.F.R. § 70.6(a)(9)(i)]
21. The permittee shall not exceed the rates in the following table during any consecutive twelve month period from SN-01 and SN-02 when firing coal, No. 2 fuel oil, or Bio-diesel. [8 CAR § 41-201 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source No.	Pollutant	tpy
SN-01 and SN-02	SO ₂	70,877.2

22. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition #21. These records may be used by the Division of Environmental Quality for enforcement purposes. 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 of Environmental Quality 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]
23. The permittee shall not exceed the rates in the following table during any consecutive twelve month period from SN-01 and SN-02 when firing coal, No. 2 fuel oil, or Bio-diesel. [8 CAR § 41-201 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source No.	Pollutant	tpy
SN-01 and SN-02	NO _x	53,348.4

24. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition # 23. These records may be used by the Division of Environmental Quality for enforcement purposes. 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 of Environmental Quality 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]
25. SN-01 and SN-02 are subject to and shall comply with all applicable provisions of the Acid Rain Program. [8 CAR § 42-1102 and 40 C.F.R. §§ 72, 73, 75,76, and 77]

26. The permittee shall submit the required electronic data reports (EDRs) to EPA Headquarters. [8 CAR § 42-1102 and 40 C.F.R. § 75]
27. Relative Accuracy tests will be performed in accordance with 40 C.F.R, Part 75. This relative accuracy test will meet the requirements under 40 C.F.R § 60 Subpart D. [8 CAR § 42-1102 and 40 C.F.R. § 75]
28. 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. [8 CAR § 42-1102 and 40 C.F.R. § 75.10 (c)]
29. The permittee shall test SN-01 and SN-02 for PM and PM₁₀ while operating under Scenario I: Coal Firing 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 PM₁₀ test shall be performed using EPA RM 201A and 202. As an alternative to RM 201A for PM₁₀, the permittee may utilize RM 5 and assume all PM collected per RM 5 is PM₁₀. As a further alternative to both RM 5 and/or 201 A, 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 (RM 5/201A) testing shall be required provided that the permittee assumes that all filterable PM measured by such CEMS is PM₁₀. If a filterable PM CEMS is used in lieu of RM 5 and/or 201A 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 0449-AOP-R3 (June 3, 2005) and every five years thereafter. [8 CAR § 41-602 and 40 C.F.R. § 52 Subpart E]
30. The permittee shall monitor the opacity of SN-01 and SN-02 using a continuous opacity monitoring system or utilize a PM CEMS with opacity monitored by periodic EPA Method 9. The permittee shall initiate corrective action when the measured opacity is greater than 20% for one six minute period per hour of not more than 27 percent opacity, and shall report any excursions where the opacity is 20% for one six minute period per hour of not more than 27 percent opacity. Corrective action shall include 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.
31. The opacity for SN-01 and SN-02 shall not exceed 20% opacity except that emissions greater than 20% opacity for one six minute period per hour of not more than 27 percent opacity, and shall report any excursions where the opacity is 20% for one six minute period per hour of not more than 27 percent opacity. 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 of Environmental Quality 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 of Environmental Quality, 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 of Environmental Quality 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 Ark. Code Ann. § 8-4-203 shall be submitted with an affidavit containing the information of 8 CAR § 40-1302 (B).
- d. Demonstrates to the satisfaction of the Division of Environmental Quality 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;
 - iii. 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 Condition # 12. [8 CAR § 40-102 (C), 8 CAR § 40-401, 8 CAR § 40-1001, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

32. Unit 1 (SN-01) and Unit 2 (SN-02) are considered affected sources under 40 C.F.R. § 63 Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and are subject, but not limited to, Specific Conditions 33 through 66. Unit 1 and Unit 2 must be in compliance with all applicable requirements by the compliance date outlined in Specific Condition 33. For

the purposes of 40 C.F.R. § 63 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]

33. An extension of compliance for 40 C.F.R. § 63 Subpart UUUUU has been granted by ADEQ for Unit 1 (SN-01) and Unit 2 (SN-02) in accordance with the provisions of § 63.6(i)(4). Accordingly, the compliance date for all applicable provisions of 40 C.F.R. § 63 Subpart UUUUU for Unit 1 (SN-01) and Unit 2 (SN-02), is established as April 16, 2016. The permittee is not required to demonstrate compliance with the provisions of 40 C.F.R. § 63 Subpart UUUUU as outlined in Specific Conditions 34 through 66, until this date, or later, as established by the provisions of 40 C.F.R. § 63 Subpart UUUUU. Nothing in this condition should be construed to require compliance with the requirements of 40 C.F.R. § 63 Subpart UUUUU, including those incorporated into this permit in Specific Conditions 34 through 66, in the event that the applicable requirements of Subpart UUUUU that warrant these conditions are stayed or vacated by the action of the D.C. Circuit Court or the Supreme Court of the United States or the US EPA. [8 CAR § 41-204 and 40 C.F.R. § 63.6(i)]
34. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable emission limits in Table 2 to 40 C.F.R. § 63 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 UUUU during periods of startup or shutdown. [8 CAR § 41-204 and 40 C.F.R. § 63.9991 and § 63.10000(a)]
35. As stated in § 63.9991, you must comply with the following applicable emission limits:¹

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. ²	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.
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, collect a minimum of 120 liters per run.
		For ASTM D6348-03 ³ or Method 320, sample for a minimum of 1 hour.

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.
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.

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 two.

² Gross electric output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

36. Unit 1 (SN-01) and Unit 2 (SN-02) shall comply with the applicable work practice standards in Table 3 to 40 C.F.R. § 63 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 40 C.F.R. § 63 Subpart UUUUU. 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 40 C.F.R. § 63 Subpart UUUUU 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 40 C.F.R. § 63 Subpart UUUUU 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.
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 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.

37. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable operating limits in Table 4 to 40 C.F.R. § 63 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).

38. 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]
- 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)(1)]
 - 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(i)]
 - 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(ii)]
 - 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(iii)]
 - 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(iv)]
 - 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 40 C.F.R. § 63 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(v)]
 - 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 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(vi)]

- a) You may choose to use separate sorbent trap monitoring systems to comply with 40 C.F.R. § 63 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 concentration during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(vi)(A)]
- 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 40 C.F.R. § 63 Subpart UUUUU for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(c)(1)(vi)(B)]
- 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 an EGU is subject to 40 C.F.R. § 63 Subpart UUUUU, 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10000(l)]

39. RESERVED

40. 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 40 C.F.R. § 63 Subpart UUUUU 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 SO₂ 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 SO₂ emissions limit in Table 1 or 2 to 40

C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(a)(2)(i)]

- ii. You must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO₂, O₂, 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 an electrical output-based emission limit, you must also collect hourly electrical load data during the performance test period. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(a)(2)(ii)]
41. If the permittee chooses to use performance testing to demonstrate initial compliance with the applicable emission limits in Table 2 to 40 C.F.R. § 63 Subpart UUUUU for Unit 1 and/or Unit 2, the tests must be conducted according to § 63.10007 and Table 5 to 40 C.F.R. § 63 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)]
42. 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 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(d)]
- a. For an affected coal-fired EGU, initial compliance with the applicable SO₂ or HCl emissions limit in Table 2 to 40 C.F.R. § 63 Subpart UUUUU may be demonstrated through use of an SO₂ or HCl CEMS installed and operated in accordance with 40 C.F.R. § 75 or Appendix B to 40 C.F.R. § 63 Subpart UUUUU. Compliance with a filterable PM emissions limit in Table 2 of 40 C.F.R. § 63 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 SO₂, PM, or HCl emissions limit in Table 2 to 40 C.F.R. § 63 Subpart UUUUU. Equation 19-19 of Method 19 in Appendix A-7 to 40 C.F.R. § 63 Subpart UUUUU must be used to calculate the 30-boiler operating day average emissions rate. For this calculation, the term Eh_j in Equation 19-19 must be in the same units of measure as the applicable HCl emission limit in Table 2 of 40 C.F.R. § 63 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 40 C.F.R. § 63 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 40 C.F.R. § 63 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 40 C.F.R. § 63 Subpart UUUUU), meets the applicable Hg emission limit in Table 2 to 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(d)(3)]
43. Unit 1 and Unit 2 are subject to the work practice standards in Table 3 of 40 C.F.R. § 63 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)]
44. 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 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)]

45. 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 §§ 63.10005(h)(1) through (5) must be followed, as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.10005(h)]
46. 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, 40 C.F.R. § 63.10005(j), and 40 C.F.R. § 63.10011(g)]
 - a. You may use the diluent cap and default electrical load values, as described in § 63.10007(f), during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(1)]
 - b. You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(2)]
 - c. You must report the information as required in § 63.10031. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(g)(3)]
 - d. If you choose to use paragraph (2) of the definition of “startup” in § 63.10042 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 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)]
47. 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, 40 C.F.R. § 63.10005(k); and 40 C.F.R. § 63.10011(e)]
48. 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 40 C.F.R. § 63 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 40 C.F.R. § 63 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 40 C.F.R. § 63 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 40 C.F.R. § 63 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 SO₂ CEMS to monitor compliance with the alternate equivalent SO₂ emission limit, the permittee must conduct all applicable periodic HCl emissions tests according to Table 5 of 40 C.F.R. § 63 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: [8 CAR § 41-204 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)]
 - a) At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter;
 - b) For annual testing:
 - (i) At least 320 calendar days, measured from the test's end date, must separate performance tests;
 - (ii) 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;

- (iii) 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
 - c) 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:
 - a) At least 15 calendar days must separate two performance tests conducted in the same quarter.
 - b) At least 107 calendar days must separate two performance tests conducted in the same calendar year.
 - c) 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)]
- 49. When conducting performance tests for the purposes of 40 C.F.R. § 63 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]
- 50. If the permittee elects to utilize emissions averaging for the purposes of demonstrating compliance with the applicable emission limitations of 40 C.F.R. § 63 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]
- 51. 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]
- 52. The permittee must demonstrate initial compliance with each applicable emission limit of 40 C.F.R. § 63 Subpart UUUUU by conducting performance testing. [8 CAR § 41-204 and 40 C.F.R. § 63.10011]
- 53. If the permittee is subject to an operating limit in Table 4 to 40 C.F.R. § 63 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 40 C.F.R. § 63 Subpart UUUUU, § 63.10007, and Table 6 to 40 C.F.R. § 63 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)]
- 54. 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 after the applicability date set forth in Specific Condition 33, 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 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(c)(1)]
- 55. For a unit that uses a CEMS to measure SO₂ or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicability date set forth in Specific Condition 33, 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 SO₂ or filterable PM emission limit in Table 2 of 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(c)(2)]

56. 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 40 C.F.R. § 63 Subpart UUUUU and to determine whether the unit qualifies for LEE status. [8 CAR § 41-204 and 40 C.F.R. § 63.10011(d)]
57. 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)]
58. 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]
59. 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 (g) of § 63.10021. [8 CAR § 41-204 and 40 C.F.R. § 63.10021]
 - b. Except as otherwise provided in § 63.10020(c), if the permittee uses a CEMS to measure SO₂, 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, CO₂, O₂, 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)]
 - c. If the permittee uses a PM CPMS data to measure compliance with an operating limit in Table 4 to 40 C.F.R. § 63 Subpart UUUUU, 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)]

- d. 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 40 C.F.R. § 63 Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard.
- e. 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)]
- f. 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)]
- g. 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)]

- h. The permittee must follow the startup or shutdown requirements as given in Table 3 to 40 CFR Part 63, Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(h)]
 - i. You may use the diluent cap and default electrical load values, as described in § 63.10007(f), during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(h)(1)]
 - ii. You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(h)(2)]
 - iii. 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. [8 CAR § 41-204 and 40 C.F.R. § 63.10021(h)(4)]
 - i. 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). [8 CAR § 41-204 and 40 C.F.R. § 63.10021(i)]
60. 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]
61. 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]
62. 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)]
63. 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 § 63.10031 as applicable. [8 CAR § 41-204 and 40 C.F.R. § 63.10031(a)]
 - i. If you are required to (or elect to) monitor Hg emissions continuously, you must meet the electronic reporting requirements of appendix A to 40 C.F.R. § 63 Subpart UUUUU.
 - ii. If you elect to monitor HCl and/or HF emissions continuously, you must meet the electronic reporting requirements of appendix B to 40 C.F.R. § 63 Subpart UUUUU. Notwithstanding this requirement, if you opt to certify your 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 you elect to monitor filterable PM emissions continuously, you 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 you elect to demonstrate continuous compliance using a PM CPMS, you 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 you elect to monitor SO₂ emission rate continuously as a surrogate for HCl, you 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 40 C.F.R Chapter I must report all deviations as defined in 40 C.F.R. § 63 Subpart UUUUU 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 reports includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 C.F.R. § 63 Subpart UUUUU, submission of the compliance reports satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance reports 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, you 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, you 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 you have 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, you must include the information in 40 CFR 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 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you 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 you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with 40 C.F.R. § 63 Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS Client Tool to submit a detailed report of your 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, 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 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 you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, 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 CEMS 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 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)]
64. 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 40 C.F.R. § 63 Subpart UUUUU, The permittee must also keep records of all supporting documentation for the Initial Notifications 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 or shutdown periods: [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)]
 - i. Should you chose 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 chose 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:
 - a) The determination of the maximum clean fuel capacity for each EGU; [8 CAR § 41-204 and 40 C.F.R. § 63.10032(f)(2)]
 - b) 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)(3)]
 - c) The information required in § 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)]
- 65. 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)]
- 66. The general provisions of § 63.1 through § 63.15 are applicable as specified in Table 9 to 40 C.F.R. § 63 Subpart UUUUU. [8 CAR § 41-204 and 40 C.F.R. § 63.10040]
- 67. 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 or Bio-diesel 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. Each 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 # 68.) [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]
- 68. The permittee shall maintain records of fuel oil or Bio-diesel sampling. These records shall be kept on site and made available to Division of Environmental Quality personnel upon request. These records may be used by the Division of Environmental Quality 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
 (Specific Conditions #69 through #71)

69. 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% O₂ on a dry basis.

70. The permittee shall test SN-01 and SN-02 for CO while operating under Scenario 1: Coal Firing Testing shall be conducted on each unit at least 90 days but no more than 240 days following the previous testing event, provided that CO testing is conducted twice per calendar year on SN-01 and SN-02. 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 #69. This testing requirement applies to SN-01 and SN-02, which operate with Low-NO_x Burners and Separated Overfire Air. [8 CAR § 41-602 and 40 C.F.R. § 52 Subpart E]
71. Reserved
72. In order to meet the Phase II Regional Haze State Implementation Plan requirements for SO₂, emissions from SN-01 and SN-02 shall not exceed 0.60 lb/MMBtu of SO₂ each per rolling 30-boiler-operating-day averaging period after August 6, 2021. A boiler-operating-day as defined by 40 CFR 52.173(c)(2) is a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]
73. Compliance with Specific Condition #72 shall be determined using data from a continuous emission monitoring system. See Specific Condition #12 [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]

74. 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]
75. 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. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

Source No.	Pollutant	lb/hr	tpy
SN-05 Scenario 1: Limited Use boiler emissions	PM ₁₀	4.5	2.0
	SO ₂	95.2	41.7
	VOC	0.4	0.2
	CO	18.7	8.2
	NO _x	32.2	14.1
	Lead	0.01	0.01
SN-05 Scenario 2: Liquid/Light liquid-fired boiler emissions	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

76. 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. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Source No.	Pollutant	lb/hr	tpy
SN-05 Scenario 1: Limited Use boiler emissions	PM	4.5	2.0
	Total HAP	0.29	0.13
	N ₂ O	0.25	0.11
	H ₂ SO ₄	1.46	0.64
SN-05 Scenario 2: Liquid/Light liquid-fired boiler emissions	PM	4.5	19.4
	Total HAP	0.29	1.27
	N ₂ O	0.25	1.07
	H ₂ SO ₄	1.46	6.39

77. The auxiliary boiler (SN-05) shall not exceed an average annual capacity factor of 10% and maintain fuel use records for the days the boiler was operating. Annual capacity factor is defined as 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. For SN-05, a 10% annual capacity factor corresponds to an annual heat input of 160,300 MMBtu per year. [8 CAR § 41-204 and 40 C.F.R. § 63.7555(d)(3) and § 63.7575]

78. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition 77. The permittee shall update these records by the 15th day of the month following the month to which the records pertain. The average annual capacity factor and the fuel usage records shall be maintained on-site, made available to Division of Environmental Quality personnel upon request, and submitted in accordance with General Provision 7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
79. As an alternative to compliance with Specific Conditions 77 and 78, 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 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]
81. Weekly observations of the opacity from SN-05 shall be conducted by personnel familiar with the permittee's visible emissions, when it operates 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 of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
82. The permittee shall maintain records of when SN-05 is operated. These records shall be maintained on site, and made available to Division of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
83. 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 84 through 134. [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

84. 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)]
85. 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)]
86. 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)]
87. 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 NO_x 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.
88. 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)]
89. 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)]
90. 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)]
91. 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)]

92. 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)]
93. 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)]
94. 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)]
95. 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.
96. 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)]
97. 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 [8 CAR § 41-204 § 63.10(b)(2)(viii)]

98. RESERVED

99. RESERVED

100. 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)]

101. 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)]

102. 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)]

103. 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

104. 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)]

105. 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)]

106. 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.
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	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05	Collect a minimum of 3 dscm per run.

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 . . .
		lb per MMBtu of heat input)	lb per MMBtu of steam output or 8.6E-04 lb per MWh)	

- 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 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.

If your unit is . . .	You must meet the following . . .
	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 your unit is . . .	You must meet the following . . .
	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 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.

- a. 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 numerical emission limit using . . .	You must meet these operating limits . . .
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).

107. 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)]
108. 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)]
109. 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)]
110. 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)]

111. 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.

112. 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)]
113. 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)]
114. 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)]
115. 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)]
116. 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)]
117. 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)]
118. 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)]
119. 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.
120. 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)]
121. 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)]
122. 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 NO_x 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.
123. 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. [8 CAR § 41-204 and C.F.R. § 63.7540(a)(12)]
124. 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)]
125. 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)]
126. 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)]
127. 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)]

128. 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)]
129. 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)]
130. 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)]
131. 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)]
132. 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)]
133. 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).

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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]

134. 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 Independence 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, is capable of emptying approximately 30 cars per hour. The rotoclone and water sprays previously used to control emissions from this process were replaced by chemical foam spray in 2001. Emissions from the rail car rotary dumper are regulated under the State Implementation Plan (SIP), 8 CAR § 41.

SN-06 - Minor emission sources at the facility include coal handling/conveying operations. Dust emissions from the coal handling operations (SN-06) were previously controlled with AMERCLONES, rotoclones and wet sprays. Beginning in 2001, dust emissions are now controlled with water and a chemical foam spray. SN-06 is separated into three sources: SN-06A, SN-06B, and SN-06C. SN-06A, Handling and Conveying Emissions, includes emission points M2, M3, M5, M6, M7, M8, M9, M12, M13, M14, M15, M16, M24, M25, M26, M27, M28, M32, and M33. SN-06B, Stacker/Reclaimer Emissions, includes emission points M17, M18, M20, M21, M22, and M23. SN-06C, Storage Piles and Haul Road Emissions, includes emission points M11, M34, M35, and M36.

Specific Conditions

135. 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
SN-03	Rail Car Rotary Dumper	PM ₁₀	0.1	0.1
		VOC	1.3	1.1
SN-06A	Handling / Conveying Emissions	PM ₁₀	0.5	2.2
		VOC	1.3	1.1
SN-06B	Stacker / Reclaimer Emissions	PM ₁₀	0.5	1.2
SN-06C	Storage Pile and Haul Road Emissions	PM ₁₀	43.8	111
		VOC	27.4	5.0

136. 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
SN-03	Rail Car Rotary Dumper	PM	0.1	0.1
SN-06A	Handling / Conveying Emissions	PM	1.1	4.6
SN-06B	Stacker / Reclaimer Emissions	PM	1.0	2.6
SN-06C	Storage Pile and Haul Road Emissions	PM	156.9	346.9

137. The permittee shall not use any chemical foam spray at SN-03 and SN-06 which contains HAPs. 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]
138. Records shall be maintained to demonstrate compliance with Condition # 137. These records shall be updated no later than the last day of the month following the month which the records represent. Such records shall be submitted to the Division of Environmental Quality in accordance with General Provision #7. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
139. The VOC content of the chemical foam spray used at SN-03 and SN-06 shall not exceed 1.42% by weight. [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]
140. Records shall be maintained to demonstrate compliance with Specific Condition # 139. These records shall be updated no later than the last day of the month following the month which the records represent. Such records shall be submitted to the Division of Environmental Quality in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
141. Usage of the chemical foam spray at SN-03 and SN-06 shall not exceed 300,000 pounds in 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]
142. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition # 141. 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 of Environmental Quality 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]

143. The permittee shall not cause to be discharged into the atmosphere any emissions which exhibit an opacity greater than or equal to 20% from the sources at SN-03, SN-06A, and SN-06B. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 41-403, 40 C.F.R. § 52 Subpart E, 8 CAR § 41-204 and 40 C.F.R. § 60.252(c)(2)]
144. Weekly observations of the opacity from sources SN-03 and 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 greater than or equal to 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:
- 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.

These records shall be updated weekly, kept on site, and made available to Division of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

145. The permittee shall conduct weekly observations of the opacity for 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:
- 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. These records shall be updated weekly, kept on site, and made available to Division of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
- 146. 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]
- 147. Nothing in this permit shall be construed to authorize a violation of the Arkansas Water and Air Pollution Control Act or the federal National Pollutant Discharge Elimination System (NPDES). [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- 148. The permittee shall use the foam sprays while the dumper (SN-03) is in operation and at all times when the Transfer Points (SN-06) including Bins, Silos, etc., that are equipped with the foam spray controls are in use 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]
- 149. The permittee shall comply with the maintenance plan submitted to the Division of Environmental Quality for the rotary car dumper, SN-03 (See Appendix C). The requirements include but are not limited to the following:
 - a. Inspect spray nozzles for plugs,
 - b. Check air pressure and flow,
 - c. Check water pressure and water/dust foam flow, and
 - d. Check for adequate dust foam chemical additive.

The permittee may use equivalent or alternative plans for this source without undergoing a modification to this permit if the new maintenance plans have been reviewed and approved by the Division of Environmental Quality. The permittee is required to submit any new maintenance plan for this source to the Division of Environmental Quality and may not implement the maintenance plan until the facility receives approval from the Division of Environmental Quality. The permittee must submit the proposed maintenance plan(s) with a cover letter explaining any changes to the following address.

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

[8 CAR § 41-204 and 40 C.F.R. § 70.6]

150. Total traffic associated with activated carbon deliveries, halide solution deliveries, and fly ash trucks hauling ash to the on-site landfill shall not exceed 61,320 vehicle miles traveled per consecutive 12-month period on paved roads and 12,045 vehicle miles traveled per consecutive 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]
151. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition # 150. Compliance shall be demonstrated by recording 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 = $(AC * DP_{AC}) + (HLD * DP_{HLD}) + ((T_{ASH}/26) * DP_{ASH})$

Monthly Total Unpaved Miles Traveled = $(AC * DUP_{AC}) + (HLD * DUP_{HLD}) + ((T_{ASH}/26) * DUP_{ASH})$

Where:

AC = monthly number of activated carbon deliveries
DP_{AC} = round trip distance over paved roads for activated carbon deliveries
HLD = monthly number of halide solution deliveries
DP_{HLD} = round trip distance over paved roads for halide solution deliveries
T_{ASH} = monthly tons of fly ash disposed in the on-site landfill
DP_{ASH} = round trip distance over paved roads for fly ash landfill disposal
DUP_{AC} = round trip distance over unpaved roads for activated carbon deliveries
DUP_{HLD} = round trip distance over unpaved roads for halide solution deliveries
DUP_{ASH} = 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(s). 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 pertain. The records shall be kept on site, and shall be provided to

Division of Environmental Quality personnel upon request. A 12-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 operate the Coal Yard Dozers more than a combined 15,000 hours per consecutive twelve (12) month period, and the water wagon shall not exceed 3,000 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]
153. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition # 152. 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 of Environmental Quality 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]
154. 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]
155. The permittee shall maintain records which demonstrate compliance with Specific Condition #154. 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 of Environmental Quality 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 with Fabric Filters

Source Description

The Independence Plant is equipped with two (2) fly ash silos. Particulate emissions from the silos are controlled by fabric filters (SN-04) with control efficiency of 99.9% for PM and 99.8% for PM₁₀.

Specific Conditions

156. 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
SN-04	Fly Ash Silos	PM ₁₀	0.1	0.1

157. 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
SN-04	Fly Ash Silos	PM	0.1	0.1

158. The permittee shall not cause to be emitted from this source any emission which exhibit an opacity greater than 5 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
159. 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:
- The date and time of the opacity observation and/or visual check.
 - 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.

These records shall be updated daily, kept on site, and made available to Division of Environmental Quality personnel upon request. The records shall be submitted to the Division of Environmental Quality in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

160. The permittee shall comply with the maintenance plan submitted to the Division of Environmental Quality for the fly ash silos (See Appendix C). Requirements include but are not limited to the following:
- 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 bags;
 - g. Check diffuser blower bearings for heat and vibration;
 - h. Check blower case for excessive heat buildup;
 - i. Check inlet filter and change as needed.

The permittee may use equivalent or alternative maintenance plans for this source without undergoing a modification to this permit. [8 CAR § 41-203 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

161. 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 # 160. The permittee shall maintain a record of these inspections. This record shall be kept on site and made available to Division of Environmental Quality personnel upon request. [8 CAR § 41-605, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64]

SN-07
Fuel Oil Storage Tank

Source Description

No. 2 Fuel Oil or bio-diesel is stored in a storage tank on site. The tank has a capacity of 596,750 gallons. The tank is cylindrical with a fixed roof. Emissions from the storage tank are 1.2 tons/year of volatile organic compounds (VOCs).

Specific Conditions

162. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by Specific Condition #163. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-07	Fuel Oil Storage Tank	VOC	1.5	0.6

163. The permittee shall not exceed the annual throughput limit of 112,000,000 gallons of No. 2 fuel oil or bio-diesel at SN-07 during any 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]
164. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition # 163. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. A twelve month rolling total and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request and submitted in accordance with General Provision # 7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-16 and SN-17
Cooling Towers

Source Description

The Independence Steam Electric Station operates two (2) cooling towers for waste heat dissipation. The cooling towers obtain makeup water from the White River and from the capture of site drainage. Emissions from the towers are particulate matter.

Specific Conditions

165. 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 # 169 and # 171. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-16 (X35)	Cooling Tower # 1	PM ₁₀	5.7	24.9
SN-17 (X36)	Cooling Tower # 2	PM ₁₀	5.7	24.9

166. 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 # 169 and # 171. [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-16 (X35)	Cooling Tower # 1	PM	5.7	24.9
SN-17 (X36)	Cooling Tower # 2	PM	5.7	24.9

167. The permittee shall not cause to be discharged to the atmosphere from this source any cooling tower drift emissions which exhibit an opacity greater than 5 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
168. Reserved
169. The total dissolved solids content shall not exceed 3,600 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]
170. The permittee shall monitor the total dissolved solids weekly when the unit is operating to demonstrate compliance with Specific Condition # 169. 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 of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

171. The circulating water flow for SN-16 and SN-17 shall not exceed 21,600 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]
172. The permittee shall verify the circulating water flow every three years to demonstrate compliance with Specific Condition #171. The flow rate for each cooling tower shall be measured by a dye dilution test, properly calibrated flow 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 of Environmental Quality personnel upon request. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-18
Degreasing Operations

Source Description

This source consists of ten (10) degreasers with a total capacity of 698 gallons. Four (4) of the degreasers are used during outage periods only. One of the degreasers, the turbine oil filter degreaser (16 gallon capacity), uses a different solvent than the other 9 degreasers.

Specific Conditions

173. 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 # 174 through # 177. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-18	Degreasing Operations	VOC	8.5	12.0

174. The VOC content of the solvent used at the turbine oil filter degreaser shall not exceed 7.59 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]
175. The VOC content of the solvent used at all degreasers other than the turbine oil filter degreaser 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]
176. The throughput of the turbine oil filter degreaser shall not exceed 32 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]
177. The throughput of all degreasers excluding the turbine oil filter degreaser shall not exceed 3,480 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]

178. The permittee shall maintain monthly records to demonstrate compliance with Specific Conditions # 176 and # 177. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. A twelve month rolling total and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request and submitted in accordance with General Provision # 7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

SN-19
Grit Blaster

Source Description

This source consists of a grit blaster used for small parts cleaning. The maximum hourly abrasive usage rate is 550 lb/hr. The emissions are controlled with a baghouse.

Specific Conditions

179. 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
SN-19 (X23)	Grit Blaster	PM ₁₀	0.7	2.7

180. 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
SN-19 (X23)	Grit Blaster	PM	1.8	7.6

181. The permittee shall not cause to be emitted from this source any emission which exhibit an opacity greater than 5 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
182. The permittee shall operate the baghouse according to the manufacturer's specifications. Compliance with this specific condition may demonstrate compliance with Specific Condition # 181. [8 CAR § 41-203 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-20
 Emergency Diesel Generator

Source Description

The Independence Plant is equipped with an 1100 Hp emergency diesel generator (SN-20).

Specific Conditions

183. 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 # 186 through # 188. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-20 (C4)	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

184. 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 # 186 through # 188, and # 191. [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-20 (C4)	Emergency Diesel Generator	PM	0.6	0.7
		Total HAP	0.02	0.02

185. The permittee shall not exceed 20% opacity from SN-20 as measured by EPA Reference Method 9. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition # 189. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]
186. The permittee shall not operate the emergency generator SN-20 in excess of 2,160 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]
187. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition # 186. 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 of

Environmental Quality personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

188. The permittee shall only use diesel or bio-diesel fuel, with a Sulfur content not greater than 0.5% by weight, to fire the emergency diesel generator (SN-20). Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions # 67 and # 68. [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]
189. The permittee shall conduct annual visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-20. Observations shall be conducted by someone trained in EPA Reference Method 9. Whenever SN-20 is in operation for more than 24 consecutive hours, the permittee shall conduct daily visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-20. 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.
190. 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 of Environmental Quality personnel upon request. These records shall contain:
 - b. The time and date of each observation/reading,
 - c. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,
 - d. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and
 - e. The name of the person conducting the observation/reading.

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

191. SN-20 is subject to 40 C.F.R. § 63 Subpart ZZZZ. The permittee shall comply with all applicable provisions of 40 C.F.R. § 63 Subpart ZZZZ which includes, but is not limited to, Specific Condition # 192. [8 CAR § 41-204 and 40 C.F.R. § 63 Subpart ZZZZ]

192. The permittee shall operate SN-20 according to the requirements in paragraphs (f)(2)(i) through (iii) of § 63.6640. If the permittee does not operate the engine according to the requirements in paragraphs (f) (2) (i) through (iii) of § 63.6640, the engine will not be considered an emergency engine under 40 C.F.R. § 63 Subpart ZZZZ and will need to meet all requirements for non-emergency engines.
- a. There is no time limit on the use of emergency stationary RICE in emergency situations.
 - b. The permittee may operate SN-20 for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.
 - c. The permittee may operate SN-20 up to 50 hours per year in non-emergency situations, The 50 hours per year for non-emergency situations cannot be used for peak shaving 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.

[8 CAR § 41-204 and 40 C.F.R. § 63.6640(f)(2)]

SN-21
 Emergency Diesel Fire Pump

Source Description

The Independence Plant is equipped with a 342 Hp emergency diesel fire pump engine (SN-21).

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 Specific Conditions # 195 through # 198. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-21 (C5)	Emergency Diesel Fire Pump	PM ₁₀	0.9	1.3
		SO ₂	0.8	1.2
		VOC	1.0	1.5
		CO	2.7	4.0
		NO _x	12.1	18.2

194. 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 # 195 through # 198 and # 201. [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-21 (C5)	Emergency Diesel Fire Pump	PM	0.9	1.3
		Total HAP	0.02	0.02

195. The permittee shall not exceed 20% opacity from SN-21 as measured by EPA Reference Method 9. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition # 199. [8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E]
196. The permittee shall not operate the emergency diesel fire pump SN-21 in excess of 3,000 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]
197. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition 196. 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 of

Environmental Quality personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

198. The permittee shall only use diesel or bio-diesel fuel, with a Sulfur content not greater than 0.5% by weight, to fire the emergency diesel fire pump (SN-21). Compliance with this Specific Condition shall be demonstrated by compliance with Specific Conditions # 67 and # 68. [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]
199. The permittee shall conduct annual visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-21. Observations shall be conducted by someone trained in EPA Reference Method 9. Whenever SN-21 is in operation for more than 24 consecutive hours, the permittee shall conduct daily visible emissions observations as a method of compliance verification for the opacity limit assigned for SN-21. 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.
200. 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 of Environmental Quality personnel upon request. These records shall contain:
 - a. The time and date of each observation/reading,
 - b. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,
 - c. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and
 - d. The name of the person conducting the observation/reading.

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

201. SN-21 is subject to 40 C.F.R. § 63 Subpart ZZZZ. The permittee shall comply with all applicable provisions of 40 C.F.R. § 63 Subpart ZZZZ which includes, but is not limited to, Specific Conditions # 202 through # 214. [8 CAR § 41-204 and 40 C.F.R. § 63 Subpart ZZZZ]

202. The permittee shall be in compliance with the applicable emission limitations and operating limitations in 40 C.F.R. § 63 Subpart ZZZZ at all times. [8 CAR § 41-204 and 40 C.F.R. § 63.6605(a)]
203. At all times the permittee shall 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. [8 CAR § 41-204 and 40 C.F.R. § 63.6605(b)]
204. The permittee shall operate and maintain SN-21 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. [8 CAR § 41-204 and 40 C.F.R. § 63.6625(e)]
205. The permittee shall install a non-resettable hour meter at SN-21. [8 CAR § 41-204 and 40 C.F.R. § 63.6625(f)]
206. The permittee shall 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. [8 CAR § 41-204 and 40 C.F.R. § 63.6625(h)]
207. The permittee has the option of utilizing an oil analysis program at SN-21 in order to extend the specified oil change requirement in Table 2c to 40 C.F.R. § 63 Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c to 40 C.F.R. § 63 Subpart ZZZZ. 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. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 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 within 2 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 changes for the engine. The analysis program must be part of the maintenance plan for the engine. [8 CAR § 41-204 and 40 C.F.R. § 63.6625(i)]

208. As stated in § 63.6602 and § 63.6640, the permittee shall comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each	The permittee shall meet the following requirement, except during periods of startup	During periods of startup the permittee shall
SN-21	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ² b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	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

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) 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 C.F.R. § 63.6(g) for alternative work practices.

[8 CAR § 41-204 and 40 C.F.R. § 63.6602]

209. The permittee shall report each instance in which the permittee did not meet each applicable emission limitation or operating limitation in Table 2c to 40 C.F.R. § 63 Subpart ZZZZ. These instances are deviations from the emission and operating limitations in 40 C.F.R. § 63 Subpart ZZZZ. These deviations must be reported according to the requirements in § 63.6650. If the permittee changes the catalyst, the permittee shall reestablish the values of the operating parameters measured during the initial performance test. When the permittee reestablishes the values of the operating parameters, the permittee shall also conduct performance test(s) to demonstrate that the permittee is meeting the required emission limitation applicable to the engine(s). [8 CAR § 41-204 and 40 C.F.R. § 63.6640(b)]
210. The permittee shall operate SN-21 according to the requirements in paragraphs (f) (1) (i) through (iii) of § 63.6640. 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) (i) through (iii) of § 63.6640, is prohibited. If the permittee does not operate the engine according to the requirements in paragraphs (f) (1) (i) through (iii) of §

63.6640, the engine will not be considered an emergency engine under 40 C.F.R. § 63 Subpart ZZZZ and will need to meet all requirements for non-emergency engines.

- a. There is no time limit on the use of emergency stationary RICE in emergency situations.
- b. The permittee may operate SN-21 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 year. 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 year.
- c. The permittee may operate SN-21 up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving 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; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

[8 CAR § 41-204 and 40 C.F.R. § 63.6640(f)(1)]

211. The permittee shall keep the records described in paragraphs (a) (1) through (a) (5), (b) (1) through (b) (3) and (c) of § 63.6655.
 - a. A copy of each notification and report that you submitted to comply with 40 C.F.R. § 63 Subpart ZZZZ, 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).

- b. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
- c. Records of performance tests and performance evaluations as required in § 63.10(b) (2) (viii).
- d. Records of all required maintenance performed on the air pollution control and monitoring equipment.
- e. 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.
- f. For each CEMS or CPMS, the permittee shall keep the records listed in paragraphs (b) (1) through (3) of § 63.6655.
- g. Records described in § 63.10(b) (2) (vi) through (xi).
- h. Previous (i.e., superseded) versions of the performance evaluation plan as required in § 63.8(d) (3).
- i. Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f) (6) (i), if applicable.

[8 CAR § 41-204 and 40 C.F.R. § 63.6655(a) and (b)]

- 212. The permittee shall keep the records required in Table 6 of 40 C.F.R. § 63 Subpart ZZZZ to show continuous compliance with each applicable emission or operating limitation. [8 CAR § 41-204 and 40 C.F.R. § 63.6655(d)]
- 213. The permittee shall keep records of the maintenance conducted on SN-21 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. [8 CAR § 41-204 and 40 C.F.R. § 63.6655(e)]
- 214. The permittee shall keep records of the hours of operation of SN-21 that are recorded through the non-resettable hour meters. 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. If the engines are used for demand response operation, the permittee shall keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response. [8 CAR § 41-204 and 40 C.F.R. § 63.6655(f)]

SN-23
 Telecom Emergency Generator

Source Description

Entergy's telecommunications support group owns and operates a small 30 kW emergency generator (SN-23). This emergency generator is powered by a propane-fired spark ignition 4-stroke engine and 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

215. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Conditions #218 through #225. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-23	Telecom Emergency Generator	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

216. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by complying with Specific Conditions #218 and #219. [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-23	Telecom Emergency Generator	PM	0.1	0.1
		Total HAP	0.04	0.01

217. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this condition shall be demonstrated by compliance with Specific Condition #218. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Limit	Regulatory Citation
23	5%	8 CAR § 40-401

218. The permittee shall only use propane as fuel for the Emergency Generator (SN-23). [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. Part 70.6]
219. The permittee shall not operate the emergency generator SN-23 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]
220. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #219. 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 of Environmental Quality personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. Part 52, Subpart E]
221. The permittee shall comply with the Phase I emission standards in 40 CFR 90.103 applicable for class II engines, over the entire life of the engine. These emission standards are listed in the table below:

Source	NO _x g/KW-hr	CO g/KW-hr
SN-23	13.4	519

[8 CAR § 41-204, 40 C.F.R. Part 60, Subpart JJJJ § 60.4233(c), § 60.4234]

222. The permittee shall install a non-resettable hour meter upon startup of SN-23. [8 CAR § 41-204, 40 C.F.R. Part 60, Subpart JJJJ § 60.4237(c)]
223. The permittee shall demonstrate compliance by purchasing an engine certified according to procedures specified in 40 CFR 60 Subpart JJJJ, for the same model year demonstrating compliance according to one of the methods specified in §60.4243(a). [8 CAR § 41-204, 40 C.F.R. Part 60, Subpart JJJJ § 60.4243(b)(1)]
224. The permittee shall operate SN-23 according the requirements in § 60.4243(d)(1) through (3) as described below:
- There is no time limit on the use of emergency engines in emergency situations.
 - The permittee may operate the emergency engines for any combination of purposes specified in § 60.4243(d)(2)(i) through (iii) for a maximum of 100 hours per calendar year.
 - The emergency engines may be operated for up to 50 hours per year for 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.

[8 CAR § 41-204, 40 C.F.R. Part 60, Subpart JJJJ, 60.4243(d)]

225. The permittee shall keep record of the following for SN-23:

- a. All notification submitted to comply with this subpart and all documentation supporting any notification.
- b. Maintenance conducted on the engines.
- c. Documentation from the manufacturer that the engines are certified to meet the required emission standards and information required by other applicable regulations.

[8 CAR § 41-204, 40 C.F.R. Part 60, Subpart JJJJ, § 60.4245(a)(1) through (3)]

226. The plant telecom emergency engine (SN-23) is subject to and shall comply with the applicable requirements of 40 CFR Part 63 Subpart ZZZZ – *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. As a new stationary RICE located at an area source of HAP emissions, SN-23 must meet the requirements of Subpart ZZZZ by meeting the applicable requirements of 40 CFR Part 60 Subpart JJJJ. No further requirements apply for SN-23 under subpart ZZZZ. [8 CAR § 41-204 and 40 C.F.R. § 63.6590(c)(1)]

SN-24
Miscellaneous Storage Tank

Source Description

SN-24 (T-29) is a 2,000 gallon tank used to store gasoline.

Specific Conditions

227. 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 #229 and #230. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-24 (T-29)	Unleaded Gasoline Tank	VOC	23.0	0.4

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 #229 and #230. [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-24 (T-29)	Unleaded Gasoline Tank	Total HAPs	1.31	0.02

229. The permittee shall store only gasoline in storage tank SN-24. 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]
230. The permittee shall not exceed an annual throughput of 15,600 gallons of gasoline at SN-24 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]
231. The permittee shall maintain monthly records to demonstrate compliance with Specific Conditions #229 and #230. The permittee shall update these records by the thirtieth day of the month following the month to which the records pertain. A twelve month rolling total and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request and submitted in accordance with General Provision # 7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

Entergy Arkansas, LLC - Independence Plant
Permit #: 0449-AOP-R19
AFIN: 32-00042

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Entergy Arkansas, LLC - Independence 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 annual throughput of coal at the facility shall not exceed 9.2 million tons of coal per 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]
9. The permittee shall maintain records which demonstrate compliance with the limit set in Plantwide Condition # 8. These records shall be updated on a monthly basis, shall be kept on site, shall be provided to Division of Environmental Quality personnel upon request, and shall be submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]
10. The permittee shall submit a compliance certification with state-only enforceable terms and conditions contained in the permit, including emission limitations, standards, or work practices. This compliance certification shall be submitted annually to the Division of Environmental Quality. All compliance certifications required by this permit shall include the following:
 - 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.

This compliance certification may be in the same format as, and may be included with, the annual compliance certification required by General Provision 21. [8 CAR § 40-904 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Acid Rain (Title IV)

11. 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 Trading Program Requirements

12. The permittee shall comply with the following TR NO_x Ozone Season Trading Program Requirements. The unit-specific monitoring provisions are attached to this Title V permit. [40 C.F.R. § 97 Subpart BBBB 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. §§ 97.513 through 97.518.
 - b. Emissions monitoring, reporting, and recordkeeping requirements.
 - i. The owners and operators, and the designated representative, of each TR NO_x Ozone Season source and each TR NO_x Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 C.F.R. §§ 97.530 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.531 (initial monitoring system certification and recertification procedures), 97.532 (monitoring system out-of-control periods), 97.533 (notifications concerning monitoring), 97.534 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.535 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
 - ii. The emissions data determined in accordance with 40 C.F.R. §§ 97.530 through 97.535 shall be used to calculate allocations of TR NO_x Ozone Season allowances under 40 C.F.R. §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_x Ozone Season 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. §§ 97.530 through 97.535 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 emissions limitation.
 - 1. 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 source and each TR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_x Ozone Season allowances available for deduction for such control period under 40 C.F.R. § 97.524(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 units at the source.
 - 2. If total NO_x emissions during a control period in a given year from the TR NO_x Ozone Season units at a TR NO_x Ozone Season source are in excess of the TR NO_x Ozone Season 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 unit at the source shall hold the TR NO_x Ozone Season allowances required for deduction under 40 C.F.R. § 97.524(d); and
 - b. The owners and operators of the source and each TR NO_x Ozone Season 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 BBBBBB and the Clean Air Act.
 - ii. TR NO_x Ozone Season assurance provisions.
 - 1. If total NO_x emissions during a control period in a given year from all TR NO_x Ozone Season units at TR NO_x Ozone Season 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 allowances available for deduction for such control period under 40 C.F.R. § 97.525(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. § 97.525(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 TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state for such control period exceed the state assurance level.
2. The owners and operators shall hold the TR NO_x Ozone Season 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 such control period.
3. Total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season 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 trading budget under 40 C.F.R. § 97.510(a) and the state's variability limit under 40 C.F.R. § 97.510(b).
4. It shall not be a violation of 40 C.F.R. § 97 Subpart BBBBBB or of the Clean Air Act if total NO_x emissions from all TR NO_x Ozone Season units at TR NO_x Ozone Season 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 TR NO_x Ozone Season units at TR NO_x Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.
5. To the extent the owners and operators fail to hold TR NO_x Ozone Season 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 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 BBBBBB and the Clean Air Act.

iii. Compliance periods.

1. A TR NO_x Ozone Season unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 C.F.R. § 97.530(b) and for each control period thereafter.
2. A TR NO_x Ozone Season 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. § 97.530(b) and for each control period thereafter.

iv. Vintage of allowances held for compliance.

1. A TR NO_x Ozone Season 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 allowance that was allocated for such control period or a control period in a prior year.
2. A TR NO_x Ozone Season allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_x Ozone Season allowance that was allocated 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 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 BBBBBB.
- vi. Limited authorization. A TR NO_x Ozone Season 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:
 1. Such authorization shall only be used in accordance with the TR NO_x Ozone Season Trading Program; and

2. Notwithstanding any other provision of 40 C.F.R. § 97 Subpart BBBBBB, 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 allowance does not constitute a property right.
- d. Title V permit revision requirements.
 - i. No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_x Ozone Season allowances in accordance with 40 C.F.R. § 97 Subpart BBBBBB.
 - ii. This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 C.F.R. §§ 97.530 through 97.535, 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. §§ 97.506(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 source and each TR NO_x Ozone Season 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.
 1. The certificate of representation under 40 C.F.R. § 97.516 for the designated representative for the source and each TR 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 certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 C.F.R. § 97.516 changing the designated representative.

2. All emissions monitoring information, in accordance with 40 C.F.R. § 97 Subpart BBBBB.
 3. 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 Trading Program.
 - ii. The designated representative of a TR NO_x Ozone Season source and each TR NO_x Ozone Season unit at the source shall make all submissions required under the TR NO_x Ozone Season Trading Program, except as provided in 40 C.F.R. § 97.518. 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 Trading Program that applies to a TR NO_x Ozone Season source or the designated representative of a TR NO_x Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_x Ozone Season units at the source.
 - ii. Any provision of the TR NO_x Ozone Season Trading Program that applies to a TR NO_x Ozone Season unit or the designated representative of a TR 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 TR NO_x Ozone Season Trading Program or exemption under 40 C.F.R. § 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_x Ozone Season source or TR 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.

Title VI Provisions

13. 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.
14. 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 Permit Shield.
 - 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.
15. 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.
16. 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.
17. 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.

Permit Shield

18. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated October 14th, 2020.

Applicable Regulations

Regulation	Description	Basis
Regulations of the Arkansas Operating Air Permit Program	8 CAR § 42-201	Facility is defined as a major source.
State Implementation Plan, Prevention of Significant Deterioration Supplement	8 CAR § 41-801	Facility is currently a major stationary source for the purpose of applicability.
New Source Performance Standards for Fossil-Fuel-Fired Steam Generators after August 17, 1978	40 C.F.R. § 60 Subpart D	Fossil-fuel fired steam generating units have heat input rate greater than 250 MMBtu/hr.
National Emission Standards for Hazardous Air Pollutants	40 C.F.R. § 61 Subpart M	Facility meets requirements for asbestos.
Acid Rain Permit Regulations	40 C.F.R. § 72 Subpart A-D	Units meet the definition of an affected source.
SO ₂ Allowance Allocations	40 C.F.R. § 73 Subpart B	Facility is on list of Phase II Allowance Allocations.
Continuous Emission Monitoring	40 C.F.R. § 75 Subpart A-D, F, and G	Facility is subject to Acid Rain Requirements for the purpose of applicability.
NO _x Emission Reduction Program	40 C.F.R. § 76	Facility is subject to Acid Rain Requirements for the purpose of applicability.
Excess Emissions	40 C.F.R. § 77	Facility is subject to Acid Rain Requirements for the purpose of applicability.
Prevention of Significant Deterioration of Air Quality (PSD)	40 C.F.R. § 52.21	Facility is subject to PSD requirements.
Protection of Stratospheric Ozone	40 C.F.R. § 82	Facility is subject to these requirements.
Mercury Air Toxics Rule	40 C.F.R. § 63 Subpart UUUUU	Facility is subject to these requirements.

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Regulation	Description	Basis
Industrial Boiler MACT	40 C.F.R. § 63 Subpart DDDDD	Facility is subject to these requirements.
RICE MACT	40 C.F.R. § 63 Subpart ZZZZ	Facility is subject to these requirements.
Cross-State Air Pollution Rule	40 C.F.R. § 97, Subpart BBBB	Facility is subject to these requirements.

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 October 24th, 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
Kerosene Fired Space Heaters (46 total)	A-1
Storage tanks less than 250 gallons storing organic liquids having a true vapor pressure less than or equal to 3.5 psia, provided that the aggregate pollutant specific emissions from all such liquid storage tanks listed as insignificant do not exceed 5 tpy of any combination of HAPs and 10 tpy of any other pollutant. (T8-T10, T12, T19, T20, T21, T23, T24A, T24B, T52, T69, T70, T71-74, T75-80, T87-89, T91)	A-2
Unit 1 ID Fan Motor Oil Reservoir	
No. 1A & 1B Condenser Vacuum Pump Lubricating Reservoir	
Unit 2 ID Fan Lube Oil Reservoir	
Unit 2 ID Fan Hydraulic Oil Reservoir	
Unit 2 ID Fan Motor Oil Reservoir	
No. 2A & 2B Condenser Vacuum Pump Lubricating Reservoir	
No. 1A & 1B Vacuum Pump Oil Separators	
No. 2A & 2B Vacuum Pump Oil Separators	
Oil Drum Storage	
Unit 1 Seal Oil Vapor Separating Tank	
Unit 2 Seal Oil Vapor Separating Tank	
Unit 1 and 2 Seal Oil Filters (4)	
Unit 1 Lube Oil Storage Tanks (3)	
Unit 2 Lube Oil Storage Tanks (3)	
Unit 1 ID Fan Lube Oil Reservoir	
Vehicle Maintenance Area Lube Oil Storage Tanks (3)	
Unit 1 ID Fan Hydraulic Reservoir	
Turbine Lube Oil Tank	

Description	Category
Storage tanks less than 10,000 gallons storing organic liquids having a true vapor pressure less than or equal to 0.5 psia, provided that the aggregate pollutant specific emissions from all such liquid storage tanks listed as insignificant do not exceed 5 tpy of any combination of HAPs and 10 tpy of any other pollutant. (T3-T6, T11, T14-T17, T22, T25, T26, T28, T33, T83-85, T-86, T-90, T-92) Unit 1 Lube Oil Bowser Unit 2 Turbine Lube Oil Reservoir Unit 2 EHC Reservoir No. 2A & 2B BFPT Lube Oil Reservoir Unit 2 Generator Seal Oil Tank Unit 2 Lube Oil Bowser Emergency Diesel Generator Fuel Oil Tank Emergency Fire Pump Diesel Tank Diesel Storage Tank - Landfill Unit 1 Turbine Lube Oil Reservoir Kerosene Storage Tank Unit 1 EHC Reservoir No. 1A & 1B BFPT Lube Oil Reservoir Unit 1 Generator Seal Oil Tank Portable Diesel Storage Tanks (2) Outage Diesel Storage Tank (500 gal) Outage Diesel Storage Tank (1,000 gal) Coal Yard Hydraulic Oil Tank (550 gal)	A-3
Chemistry Lab Vent Hood (Wet Lab) Bench Scale Analysis (V48) Mix Coal Lab Vent Hood (V49)	A-5
Other activities for which the facility demonstrates that no enforceable permit conditions are necessary to insure compliance with any applicable law or regulation provided that the emissions are less than 5 tpy of any pollutant regulated under this regulation or less than 1 tpy of a single HAP or 2.5 tpy of any combination of HAPs. Unit 1 Turbine Lube Oil Storage Tank (T2) Unit 2 Lube Oil Storage Tank (T13) Oil/Water Separator-RCD (W6) Oil/Water Separator (W7) Oil/Waste Basin (W8) Unleaded Gasoline Dispensing Station (X1) Diesel Fuel Dispensing Station (5 different locations) (X4) Kerosene Dispensing Tank #1 (X5) Aerosol Lubricant Fugitives (X57)	A-13

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Description	Category
Aerosol Degreaser Fugitives (X58) Insecticide Fugitives (X59) Aerosol Can Puncture Station (X60) Unit 1 Economizer Ash Silos (M60) Unit 2 Economizer Ash Silos (M61) Unit 1 Activated Carbon Silo (X115) Unit 2 Activated Carbon Silo (X116) (2) Powdered Halide Hoppers (X61) Bottom Ash Bunker System (X62) Fly Ash Railcar Transloader (X63)	
AC Chiller – Pressure Tanks (X38-X45 and X53-X56)	Pressure Tanks No Emissions

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://portal.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), 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.

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[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 C.F.R. § 60, Subpart D – *Standards of Performance for Fossil-Fuel-Fired Steam Generators
for Which Construction is Commenced After August 17, 1971*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart D Standards of Performance for Fossil-Fuel-Fired Steam Generators

§ 60.40 Applicability and designation of affected facility.

§ 60.41 Definitions.

§ 60.42 Standard for particulate matter (PM).

§ 60.43 Standard for sulfur dioxide (SO₂).

§ 60.44 Standard for nitrogen oxides (NO_x).

§ 60.45 Emissions and fuel monitoring.

§ 60.46 Test methods and procedures.

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 of 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 SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO₂ 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 (SO₂).

- (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 SO₂ in excess of:
 - (1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.
 - (2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.
- (b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

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

Where:

PS_{SO₂} = Prorated standard for S_{O₂} when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

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

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

- (c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
- (d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.
- (e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

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

§ 60.44 Standard for nitrogen oxides (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 NO₂ 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:

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

Where:

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

w = Percentage of total heat input derived from lignite;

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

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

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

- (c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_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 SO₂ or NO_x, a CEMS for measuring either O₂ or CO₂ 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, SO₂, 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 SO₂ 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, SO₂ and NO_x span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO ₂	Span value for NO _x
Gas	(¹)	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

¹ Not applicable.

Where:

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

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

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

- (ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the SO₂ 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 O₂ is selected, the measurement of the pollutant concentration and O₂ 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:

$$E = CF \left(\frac{20.9}{100 - \%O_2} \right)$$

Where E, C, F, and %O₂ are determined under paragraph (f) of this section.

- (2) When a CEMS for measuring CO₂ is selected, the measurement of the pollutant concentration and CO₂ concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

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

Where E, C, F_c and %CO₂ are determined under paragraph (f) of this section.

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

- (1) E = pollutant emissions, ng/J (lb/MMBtu).
- (2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO₂ and 46.01 for NO_x.
- (3) %O₂, %CO₂ = O₂ or CO₂ 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 CO₂ generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:
 - (i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2,723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$ scm CO₂/J (1,980 scf CO₂/MMBtu).
 - (ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$ scm CO₂/J (1,810 scf CO₂/MMBtu).
 - (iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$ scm CO₂/J (1,430 scf CO₂/MMBtu).
 - (iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO₂/J (1,040 scf CO₂/MMBtu) for natural gas, 0.322×10^{-7} scm CO₂/J (1,200 scf CO₂/MMBtu) for propane, and 0.338×10^{-7} scm CO₂/J (1,260 scf CO₂/MMBtu) for butane.
 - (v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$ scm CO₂/J (1,840 scf CO₂/MMBtu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/MMBtu) and $F_c = 0.494 \times 10^{-7}$ scm CO₂/J (1,860 scf CO₂/MMBtu).
 - (vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO₂/J (1,920 scf CO₂/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 F_c factor (scm CO₂/J, or scf CO₂/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

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

$$F_c = \frac{2.0 \times 10^{-4} (\%C)}{GCV \text{ (SI units)}}$$

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

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

$$F_c = \frac{321 \times 10^4 (\%C)}{GCV \text{ (English units)}}$$

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- (i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O₂ (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) GCV 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 F_c 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 F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

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

Where:

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

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

n = Number of fuels being burned in combination.

- (g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
- (1) **Opacity.** Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
- (i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.
- (ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.
- (2) **Sulfur dioxide.** Excess emissions for affected facilities are defined as:
- (i) For affected facilities electing not to comply with § 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in § 60.43; or
- (ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in § 60.43. Facilities complying with the 30-day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.
- (3) **Nitrogen oxides.** Excess emissions for affected facilities using a CEMS for measuring NO_x are defined as:
- (i) For affected facilities electing not to comply with § 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in § 60.44; or

- (ii) For affected facilities electing to comply with § 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_x as measured by a CEMS exceed the applicable standard in § 60.44. Facilities complying with the 30-day NO_x standard shall use the most current associated NO_x compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.
- (4) **Particulate matter.** Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in § 60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.
- (h) The owner or operator of an affected facility subject to the opacity limits in § 60.42 that elects to monitor emissions according to the requirements in § 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.
 - (1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.
 - (i) Dates and time intervals of all opacity observation periods;
 - (ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
 - (iii) Copies of all visible emission observer opacity field data sheets;
 - (2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.
 - (i) Dates and time intervals of all visible emissions observation periods;
 - (ii) Name and affiliation for each visible emission observer participating in the performance test;
 - (iii) Copies of all visible emission observer opacity field data sheets; and
 - (iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.
 - (3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009; 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, SO₂, and NO_x standards in §§ 60.42, 60.43, and 60.44 as follows:

- (1) The emission rate (E) of PM, SO₂, or NO_x shall be computed for each run using the following equation:

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

Where:

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

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

%O₂ = O₂ concentration, percent dry basis; and

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

- (2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.
- (i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).
- (ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O₂ concentration (%O₂). The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of the sample O₂ concentrations at all traverse points.
- (iii) If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O₂ 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 SO₂ 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 O₂ concentration (%O₂). The O₂ sample shall be taken simultaneously with, and at the same point as, the SO₂ sample. The SO₂ emission rate shall be computed for each pair of SO₂ and O₂ samples. The SO₂ 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 SO₂ 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 O₂ concentration (%O₂). 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 O₂ 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, SO₂ and NO_x may be determined by using the Fc factor, provided that the following procedure is used:
 - (i) The emission rate (E) shall be computed using the following equation:

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

Where:

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

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

%CO₂ = CO₂ concentration, percent dry basis; and

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

- (ii) If and only if the average F_c 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 O₂ and CO₂ 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 SO₂ may be determined simultaneously with the Method 5 of appendix A of this part 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 SO₂ (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 SO₂ 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 O₂ concentration (%O₂) 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

40 C.F.R. § 75 - *Continuous Emission Monitoring Systems Conditions, Revised September 2013*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 75 Continuous Emission Monitoring

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§ 75.66 Petitions to the Administrator.

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§ 75.72 Determination of NO_x mass emissions for common stack and multiple stack

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§ 75.73 Recordkeeping and reporting.

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Optional SO₂ Emissions Data Protocol for Gas-Fired and Oil-Fired
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[Reserved]*

*Appendix I to Part 75—Optional F—Factor/Fuel Flow Method
[Reserved]*

*Appendix J to Part 75—Compliance Dates for Revised Recordkeeping
Requirements and Missing Data Procedures [Reserved]*

PART 75—CONTINUOUS EMISSION MONITORING

Authority: 42 U.S.C. 7401-7671q and 7651k note.

Source: 58 FR 3701, Jan. 11, 1993, unless otherwise noted.

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Subpart A—General

§ 75.1 Purpose and scope.

- (a) **Purpose.** The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401-7671q as amended by Public Law 101-549 (November 15, 1990) [the Act]. In addition, this part sets forth provisions for the monitoring, recordkeeping, and reporting of NO_x mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.
- (b) **Scope.**
- (1) The regulations established under this part include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO₂ emissions, volumetric flow, NO_x emissions, opacity, CO₂ emissions and SO₂ emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring systems, certification tests and procedures, and quality assurance tests and procedures are included in appendices A and B to this part. Criteria for alternative monitoring systems and provisions to account for missing data from certified continuous emission monitoring systems or approved alternative monitoring systems are also included in the regulation.
 - (2) Statistical estimation procedures for missing data are included in appendix C to this part. Optional protocols for estimating SO₂ mass emissions from gas-fired or oil-fired units and NO_x emissions from gas-fired peaking or oil-fired peaking units are included in appendices D and E, respectively, to this part. Requirements for recording and recordkeeping of monitoring data and for quarterly electronic reporting also are specified. Procedures for conversion of monitoring data into units of the standard are included in appendix F to this part. Procedures for the monitoring and calculation of CO₂ emissions are included in appendix G of this part.

[58 FR 3701, Jan. 11, 1993; 58 FR 34126, June 23, 1993; 58 FR 40747, July 30, 1993; 63 FR 57498, Oct. 27, 1999; 67 FR 40421, June 12, 2002]

§ 75.2 Applicability.

- (a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO₂ or NO_x.
- (b) The provisions of this part do not apply to:
- (1) A new unit for which a written exemption has been issued under § 72.7 of this chapter (any new unit that serves one or more generators with total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 percent or less by weight may apply to the Administrator for an exemption); or
 - (2) Any unit not subject to the requirements of the Acid Rain Program due to operation of any paragraph of § 72.6(b) of this chapter; or
 - (3) An affected unit for which a written exemption has been issued under § 72.8 of this chapter and an exception granted under § 75.67 of this part.

- (c) The provisions of this part apply to sources subject to a State or federal NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

[58 FR 3701, Jan. 11, 1993, as amended at 58 FR 15716, Mar. 23, 1993; 60 FR 26516, May 17, 1995; 63 FR 57499, Oct. 27, 1998; 70 FR 28678, May 18, 2005; 76 FR 17306, Mar. 28, 2011]

§ 75.3 General Acid Rain Program provisions.

The provisions of part 72, including the following, shall apply to this part:

- (a) § 72.2 (Definitions);
- (b) § 72.3 (Measurements, Abbreviations, and Acronyms);
- (c) § 72.4 (Federal Authority);
- (d) § 72.5 (State Authority);
- (e) § 72.6 (Applicability);
- (f) § 72.7 (New Unit Exemption);
- (g) § 72.8 (Retired Units Exemption);
- (h) § 72.9 (Standard Requirements);
- (i) § 72.10 (Availability of Information); and
- (j) § 72.11 (Computation of Time).

In addition, the procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 75.4 Compliance dates.

- (a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_x mass emissions become applicable on the deadlines specified in the applicable State or federal NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO₂, NO_x, CO₂, opacity, moisture and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (i) of this section):

- (1) For a unit listed in table 1 of § 73.10(a) of this chapter, November 15, 1993.

- (2) For a substitution or a compensating unit that is designated under an approved substitution plan or reduced utilization plan pursuant to § 72.41 or § 72.43 of this chapter, or for a unit that is designated an early election unit under an approved NO_x compliance plan pursuant to part 76 of this chapter, that is not conditionally approved and that is effective for 1995, the earlier of the following dates:
 - (i) January 1, 1995; or
 - (ii) 90 days after the issuance date of the Acid Rain permit (or date of approval of permit revision) that governs the unit and contains the approved substitution plan, reduced utilization plan, or NO_x compliance plan.
- (3) For either a Phase II unit, other than a gas-fired unit or an oil-fired unit, or a substitution or compensating unit that is not a substitution or compensating unit under paragraph (a)(2) of this section: January 1, 1995.
- (4) For a gas-fired Phase II unit or an oil-fired Phase II unit, January 1, 1995, except that installation and certification tests for continuous emission monitoring systems for NO_x and CO₂ or excepted monitoring systems for NO_x under appendix E or CO₂ estimation under appendix G of this part shall be completed as follows:
 - (i) For an oil-fired Phase II unit or a gas-fired Phase II unit located in an ozone nonattainment area or the ozone transport region, not later than July 1, 1995; or
 - (ii) For an oil-fired Phase II unit or a gas-fired Phase II unit not located in an ozone nonattainment area or the ozone transport region, not later than January 1, 1996.
- (5) For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the expiration date of a combustion source's opt-in permit under § 74.14(e) of this chapter.
- (b) In accordance with § 75.20, the owner or operator of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO₂, NO_x, CO₂, opacity, and volumetric flow are installed and all certification tests are completed on or before the later of the following dates:
 - (1) January 1, 1995, except that for a gas-fired unit or oil-fired unit located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_x and CO₂ monitoring systems shall be July 1, 1995 and for a gas-fired unit or an oil-fired unit not located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_x and CO₂ monitoring systems shall be January 1, 1996; or
 - (2) 180 calendar days after the date the unit commences commercial operation, notice of which date shall be provided under subpart G of this part.
- (c) In accordance with § 75.20, the owner or operator of any unit affected under any paragraph of § 72.6(a)(3)(ii) through (vii) of this chapter shall ensure that all monitoring systems required under this part for monitoring of SO₂, NO_x, CO₂, opacity, and volumetric flow are installed and all certification tests are completed on or before the later of the following dates:

- (1) January 1, 1995, except that for a gas-fired unit or oil-fired unit located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_x and CO₂ monitoring systems shall be July 1, 1995 and for a gas-fired unit or an oil-fired unit not located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_x and CO₂ monitoring systems shall be January 1, 1996; or
 - (2) 180 calendar days after the date on which the unit becomes subject to the requirements of the Acid Rain Program, notice of which date shall be provided under subpart G of this part.
- (d) This paragraph (d) applies to affected units under the Acid Rain Program and to units subject to a State or Federal pollutant mass emissions reduction program that adopts the emission monitoring and reporting provisions of this part. In accordance with § 75.20, for an affected unit which, on the applicable compliance date, is either in long-term cold storage (as defined in § 72.2 of this chapter) or is shut down as the result of a planned outage or a forced outage, thereby preventing the required continuous monitoring system certification tests from being completed by the compliance date, the owner or operator shall provide notice of such unit storage or outage in accordance with § 75.61(a)(3) or § 75.61(a)(7), as applicable. For the planned and unplanned unit outages described in this paragraph (d), the owner or operator shall ensure that all of the continuous monitoring systems for SO₂, NO_x, CO₂, opacity, and volumetric flow rate required under this part (or under the applicable State or Federal mass emissions reduction program) are installed and that all required certification tests are completed no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit recommences commercial operation, notice of which date shall be provided under § 75.61(a)(3) or § 75.61(a)(7), as applicable. The owner or operator shall determine and report SO₂ concentration, NO_x emission rate, CO₂ concentration, and flow rate data (as applicable) for all unit operating hours after the applicable compliance date until all of the required certification tests are successfully completed, using either:
- (1) The maximum potential concentration of SO₂ (as defined in section 2.1.1.1 of appendix A to this part), the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum potential CO₂ concentration, as defined in section 2.1.3.1 of appendix A to this part; or
 - (2) The conditional data validation provisions of § 75.20(b)(3); or
 - (3) Reference methods under § 75.22(b); or
 - (4) Another procedure approved by the Administrator pursuant to a petition under § 75.66.
- (e) In accordance with § 75.20, if the owner or operator of an affected unit completes construction of a new stack or flue, or a flue gas desulfurization system or add-on NO_x emission controls, after the applicable deadline in paragraph (a), (b), or (c) of this section:
- (1) Except as otherwise provided in paragraph (e)(3) of this section, the owner or operator shall ensure that all required certification and/or recertification and/or diagnostic tests of the monitoring systems required under this part (i.e., the SO₂, NO_x, CO₂, O₂, opacity, volumetric flow rate, and moisture monitoring systems, as applicable) are completed not later than 90 unit operating days or 180 calendar days (whichever occurs first) after:
 - (i) For the event of construction of a new stack or flue, the date that emissions first exit to the atmosphere through the new stack or flue, notice of which date shall be provided under subpart G of this part; or

- (ii) For the event of installation of a flue gas desulfurization system or add-on NO_x emission controls, the date that reagent is first injected into the flue gas desulfurization system or the add-on NO_x emission controls, as applicable, notice of which date shall be provided under subpart G of this part.
- (2) The owner or operator shall determine and report, as applicable, SO₂ concentration, NO_x concentration, NO_x emission rate, CO₂ concentration, O₂ concentration, volumetric flow rate, and moisture data for all unit or stack operating hours after emissions first pass through the new stack or flue, or reagent is first injected into the flue gas desulfurization system or add-on NO_x emission controls, as applicable, until all required certification and/or recertification and/or diagnostic tests are successfully completed, using:
 - (i) Quality-assured data recorded by a previously-certified monitoring system for which the event requires no additional testing;
 - (ii) The applicable missing data substitution procedures under §§ 75.31 through 75.37;
 - (iii) The conditional data validation procedures of § 75.20(b)(3), except that conditional data validation may, if necessary, be used for the entire window of time provided under paragraph (e)(1) of this section in lieu of the periods specified in § 75.20(b)(3)(iv);
 - (iv) Reference methods under § 75.22(b);
 - (v) For the event of installation of a flue gas desulfurization system or add-on NO_x emission controls, quality-assured data recorded on the high measurement scale of the monitor that measures the pollutant being removed by the add-on emission controls (i.e., SO₂ or NO_x, as applicable), if, pursuant to section 2 of appendix A to this part, two spans and ranges are required for that monitor and if the high measurement scale of the monitor has been certified according to § 75.20(c), section 6 of appendix A to this part, and, if applicable, paragraph (e)(4)(i) of this section. Data recorded on the certified high scale that ordinarily would be required to be recorded on the low scale, pursuant to section 2.1.1.4(g) or 2.1.2.4(f) of appendix A to this part, may be reported as quality-assured for a period not to exceed 60 unit or stack operating days after the date and hour that reagent is first injected into the control device, after which one or more of the options provided in paragraphs (e)(2)(ii), (e)(2)(iii), (e)(2)(iv) and (e)(2)(vi) of this section must be used to report SO₂ or NO_x concentration data (as applicable) for each operating hour in which these low emissions occur, until certification testing of the low scale of the monitor is successfully completed; or
 - (vi) Another procedure approved by the Administrator pursuant to a petition under § 75.66.
- (3) If a particular project involves both the event of new stack or flue construction and the event of installation of a flue gas desulfurization system or add-on NO_x emission controls, the owner or operator shall either:
 - (i) Complete all of the monitoring system certification and/or recertification and/or diagnostic testing requirements of both events within the window of time provided under paragraph (e)(1)(i) of this section; or
 - (ii) Complete all of the monitoring system certification and/or recertification and/or diagnostic testing requirements of each event within the separate window of time applicable to such event provided under paragraph (e)(1) of this section.

- (4) For the project described in paragraph (e)(3) of this section, the emissions data from each CEMS installed on the new stack recorded in the interval of time starting on the date and hour on which emissions first exit to the atmosphere through the new stack and ending on the hour before the date and hour on which reagent is first injected into the control device may be reported as quality assured:
 - (i) For the CEMS that includes the monitor that measures the pollutant being removed by the add-on emission controls (*i.e.*, SO₂ or NO_x, as applicable):
 - (A) Only if the relative accuracy test audit (RATA) of the high measurement scale of the monitor is successfully completed either prior to the date and hour of the first injection of reagent into the emission control device, or after that date and hour during a period when the control device is not operating, but still within the window of time provided under paragraph (e)(1)(i) of this section, and the rest of the certification tests required under § 75.20(c) and section 6 of appendix A to this part for the high measurement scale of the monitor are successfully completed within the window of time provided under paragraph (e)(1)(i) of this section;
 - (B) Beginning with:
 - (1) The first unit or stack operating hour after successful completion of all of the certification tests in accordance with paragraph (e)(4)(i)(A) of this section; or
 - (2) The hour of the probationary calibration error test (see § 75.20(b)(3)(ii)), if conditional data validation is used and all of the certification tests are successfully completed in accordance with paragraph (e)(4)(i)(A) of this section, with no test failures. If any required test is failed or aborted or is otherwise not in accordance with paragraph (e)(4)(i)(A) of this section, data validation shall be done according to § 75.20(b)(3)(vii).
 - (ii) For a CEMS other than one addressed in paragraph (e)(4)(i) of this section:
 - (A) Only if the relative accuracy test audit (RATA) of the CEMS is successfully completed either prior to the date and hour of the first injection of reagent into the emission control device, or after that date and hour during a period when the control device is not operating, but still within the window of time provided under paragraph (e)(1)(i) of this section, and the rest of the certification tests required under § 75.20(c) and section 6 of appendix A to this part for the CEMS are successfully completed within the window of time provided under paragraph (e)(1)(i) of this section;
 - (B) Beginning with:
 - (1) The first unit or stack operating hour after successful completion of all of the certification tests in accordance with paragraph (e)(4)(ii)(A) of this section; or
 - (2) The hour of the probationary calibration error test (see § 75.20(b)(3)(ii)), if conditional data validation is used and all of the certification tests are successfully completed in accordance with paragraph (e)(4)(ii)(A) of this section, with no test failures. If any required test is failed or aborted or is otherwise not in accordance with paragraph (e)(4)(ii)(A) of this section, data validation shall be done according to § 75.20(b)(3)(vii).

(f) In accordance with § 75.20, the owner or operator of an affected gas-fired or oil-fired peaking unit, if planning to use appendix E of this part, shall ensure that the required certification tests for excepted monitoring systems under appendix E are completed for backup fuel, as defined in § 72.2 of this chapter, no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit first combusts the backup fuel following the certification testing with the primary fuel. If the required testing is completed by this deadline, the appendix E correlation curve derived from the test results may be used for reporting data under this part beginning with the first date and hour that the backup fuel is combusted, provided that the fuel flowmeter for the backup fuel was certified as of that date and hour. If the required appendix E testing has not been successfully completed by the compliance date in this paragraph, then, until the testing is completed, the owner or operator shall report NO_x emission rate data for all unit operating hours that the backup fuel is combusted using either:

- (1) The fuel-specific maximum potential NO_x emission rate, as defined in § 72.2 of this chapter; or
- (2) Reference methods under § 75.22(b) of this part; or
- (3) Another procedure approved by the Administrator pursuant to a petition under § 75.66.

(g) The provisions of this paragraph shall apply unless an owner or operator is exempt from certifying a fuel flowmeter for use during combustion of emergency fuel under section 2.1.4.3 of appendix D to this part, in which circumstance the provisions of section 2.1.4.3 of appendix D shall apply. In accordance with § 75.20, whenever the owner or operator of a gas-fired or oil-fired unit uses an excepted monitoring system under appendix D or E of this part and combusts emergency fuel as defined in § 72.2 of this chapter, then the owner or operator shall ensure that a fuel flowmeter measuring emergency fuel is installed and the required certification tests for excepted monitoring systems are completed by no later than 30 unit operating days after the first date after January 1, 1995 that the unit combusts emergency fuel. For all unit operating hours that the unit combusts emergency fuel after January 1, 1995 until the owner or operator installs a flowmeter for emergency fuel and successfully completes all required certification tests, the owner or operator shall determine and report SO₂ mass emission data using either:

- (1) The maximum potential fuel flow rate, as described in appendix D of this part, and the maximum sulfur content of the fuel, as described in section 2.1.1.1 of appendix A of this part;
- (2) Reference methods under § 75.22(b) of this part; or
- (3) Another procedure approved by the Administrator pursuant to a petition under § 75.66.

(h) [Reserved]

(i) In accordance with § 75.20, the owner or operator of each affected unit at which SO₂ concentration is measured on a dry basis or at which moisture corrections are required to account for CO₂ emissions, NO_x emission rate in lb/mmBtu, heat input, or NO_x mass emissions for units in a NO_x mass reduction program, shall ensure that the continuous moisture monitoring system required by this part is installed and that all applicable initial certification tests required under § 75.20(c)(5), (c)(6), or (c)(7) for the continuous moisture monitoring system are completed no later than the following dates:

- (1) April 1, 2000, for a unit that is existing and has commenced commercial operation by January 2, 2000;
- (2) For a new affected unit which has not commenced commercial operation by January 2, 2000, 90 unit operating days or 180 calendar days (whichever occurs first) after the date the unit commences commercial operation; or

- (3) For an existing unit that is shutdown and is not yet operating by April 1, 2000, 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit recommences commercial operation.
- (j) If the certification tests required under paragraph (b) or (c) of this section have not been completed by the applicable compliance date, the owner or operator shall determine and report SO₂ concentration, NO_x emission rate, CO₂ concentration, and flow rate data for all unit operating hours after the applicable compliance date in this paragraph until all required certification tests are successfully completed using either:
 - (1) The maximum potential concentration of SO₂, as defined in section 2.1.1.1 of appendix A to this part, the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum potential CO₂ concentration, as defined in section 2.1.3.1 of appendix A to this part;
 - (2) Reference methods under § 75.22(b); or
 - (3) Another procedure approved by the Administrator pursuant to a petition under § 75.66.

[60 FR 17131, Apr. 4, 1995, as amended at 60 FR 26516, May 17, 1995; 63 FR 57499, Oct. 27, 1998; 64 FR 28588, May 26, 1999; 67 FR 40421, June 12, 2002; 73 FR 4340, Jan. 24, 2008; 76 FR 17306, Mar. 28, 2011; 76 FR 50132, Aug. 12, 2011]

§ 75.5 Prohibitions.

- (a) A violation of any applicable regulation in this part by the owners or operators or the designated representative of an affected source or an affected unit is a violation of the Act.
- (b) No owner or operator of an affected unit shall operate the unit without complying with the requirements of §§ 75.2 through 75.75 and appendices A through G to this part.
- (c) No owner or operator of an affected unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with §§ 75.23, 75.48 and 75.66.
- (d) No owner or operator of an affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO₂, NO_x or CO₂ to the atmosphere without accounting for all such emissions in accordance with the provisions of §§ 75.10 through 75.19.
- (e) No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO₂, NO_x, or CO₂ emissions discharged to the atmosphere, except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to § 75.21 and appendix B of this part.
- (f) No owner or operator of an affected unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, the continuous opacity monitoring system, or any other approved emission monitoring system under this part, except under any one of the following circumstances:
 - (1) During the period that the unit is covered by an approved retired unit exemption under § 72.8 of this chapter that is in effect; or

- (2) The owner or operator is monitoring emissions from the unit with another certified monitoring system or an excepted methodology approved by the Administrator for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or
- (3) The designated representative submits notification of the date of recertification testing of a replacement monitoring system in accordance with §§ 75.20 and 75.61, and the owner or operator recertifies thereafter a replacement monitoring system in accordance with § 75.20.

[58 FR 3701, Jan. 11, 1993, as amended at 58 FR 40747, July 30, 1993; 60 FR 26517, May 17, 1995; 64 FR 28589, May 26, 1999]

§ 75.6 Incorporation by reference.

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and a notice of any change in these materials will be published in the FEDERAL REGISTER. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Public Information Reference Unit of the U.S. EPA, 401 M St., SW., Washington, DC and at the Library (MD-35), U.S. EPA, Research Triangle Park, North Carolina or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030, or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

- (a) The following materials are available for purchase from the following address: American Society for Testing and Material (ASTM) International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, Pennsylvania, 19428-2959, phone: 610-832-9585, http://www.astm.org/DIGITAL_LIBRARY/index.shtml.
 - (1) ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), for appendices A and D of this part.
 - (2) D240-00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, for appendices A, D and F of this part.
 - (3) ASTM D287-92 (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), for appendix D of this part.
 - (4) ASTM D388-99, Standard Classification of Coals by Rank, incorporation by reference for appendix F of this part.
 - (5) [Reserved]
 - (6) ASTM D1072-06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, for appendix D of this part.
 - (7) ASTM D1217-993 (Reapproved 1998), Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, for appendix D of this part.
 - (8) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables, for appendix D of this part.
 - (9) ASTM D1298-99, Standard Test Method for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, for appendix D of this part.

- (10) ASTM D1480-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, for appendix D of this part.
- (11) ASTM D1481-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, for appendix D of this part.
- (12) ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), for appendices A and D of the part.
- (13) ASTM D1826-94 (Reapproved 1998), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for appendices D and F to this part.
- (14) ASTM D1945-96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, for appendices F and G of this part.
- (15) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography, for appendices F and G of this part.
- (16) [Reserved]
- (17) ASTM D2013-01, Standard Practice for Preparing Coal Samples for Analysis, for appendix F of this part.
- (18) [Reserved]
- (19) ASTM D2234-00, Standard Practice for Collection of a Gross Sample of Coal, for appendix F of this part.
- (20) [Reserved]
- (21) ASTM D2502-92 (Reapproved 1996), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements, for appendix G of this part.
- (22) ASTM D2503-92 (Reapproved 1997), Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, for appendix G of this part.
- (23) ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, for appendices A and D of this part.
- (24) ASTM D3174-00, Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal, for appendix G of this part.
- (25) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, for appendices A and F of this part.
- (26) ASTM D3177-02 (Reapproved 2007), Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, for appendix A of this part.
- (27) ASTM D5373-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke, for appendix G of this part.
- (28) ASTM D3238-95 (Reapproved 2000), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, for appendix G of this part.

- (29) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, for appendix D of this part.
- (30) [Reserved]
- (31) ASTM D3588-98, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, for appendices D and F to this part.
- (32) ASTM D4052-96 (Reapproved 2002), Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter, for appendix D of this part.
- (33) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, for appendix D of this part.
- (34) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, for appendix D of this part.
- (35) ASTM D4239-02, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods, for appendix A of this part.
- (36) ASTM D4294-98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry, for appendices A and D of this part.
- (37) ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, for appendix D of this part.
- (38) [Reserved]
- (39) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, for appendices D and F to this part.
- (40) ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, for appendices F and G to this part.
- (41) ASTM D5373-02 (Reapproved 2007), "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke," for appendix G to this part.
- (42) ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, for appendix D of this part.
- (43) [Reserved]
- (44) [Reserved]
- (45) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, for appendix D of this part.
- (46) ASTM D4809-00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), for appendices D and F of this part.
- (47) ASTM D5865-01a, Standard Test Method for Gross Calorific Value of Coal and Coke, for appendices A, D, and F of this part.
- (48) ASTM D7036-04, Standard Practice for Competence of Air Emission Testing Bodies, for § 75.21, § 75.59, and appendix A to this part.

- (49) ASTM D5453-06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, for appendix D of this part.
- (50) ASTM D5865-10 (Approved January 1, 2010), Standard Test Method for Gross Calorific Value of Coal and Coke, for appendices A, D, and F of this part.
- (b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, New Jersey 07007-2900:
 - (1) ASME MFC-3M-2004 (Revision of ASME MFC-3M-1989 (R1995)), Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, for appendix D of this part.
 - (2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters, for appendix D of this part.
 - (3) ASME-MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, for appendix D of this part.
 - (4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, for appendix D of this part.
 - (5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, for appendix D of this part.
 - (6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for appendix D of this part.
- (c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:
 - (1) ISO 8316: 1987(E) Measurement of Liquid Flow in closed Conduits-Method by Collection of the Liquid in a Volumetric Tank, for appendices D and E of this part.
 - (2) [Reserved]
- (d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:
 - (1) GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, for appendices D, E, and F of this part.
 - (2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, for appendices D, F, and G of this part.
- (e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:
 - (1) American Gas Association Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition) and Part 3: Natural Gas Applications (August 1992 Edition), for appendices D and E of this part.
 - (2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April, 1996), for appendix D to this part.

- (f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005-4070.
- (1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3—Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2—Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996; Section 4—Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, March 2006); and Section 5—Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19.
- (2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992), for § 75.19.
- (3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, Section 3—Small Volume Provers, First Edition, July 1988, Reaffirmed Oct 1993, and Section 5—Master-Meter Provers, Second Edition, May 2000, for appendix D to this part.
- (4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices (First Edition, August 2005), for appendix D to this part.
- (g) A copy of the following material is available from <http://www.epa.gov/ttn/emc/news.html> (see postings for Sections 1, 2, 3, 4, Appendices, Spreadsheets, and the “Read before downloading Section 2” revision posted August 27, 1999): EPA-600/R-97/121, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, September 1997, as amended August 25, 1999, U.S. Environmental Protection Agency, for § 75.21, and appendix A to this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26517, May 17, 1995; 61 FR 59157, Nov. 20, 1996; 63 FR 57499, Oct. 27, 1998; 64 FR 28589, May 26, 1999; 67 FR 40422, June 12, 2002; 70 FR 28678, May 18, 2005; 70 FR 51269, Aug. 30, 2005; 73 FR 4341, Jan. 24, 2008; 76 FR 17307, Mar. 28, 2011; 77 FR 2460, Jan. 18, 2012]

Editorial Note: At 70 FR 28678, May 18, 2005, § 75.6 was amended, however, certain amendments could not be incorporated due to inaccurate amendatory instruction.

§§ 75.7-75.8 [Reserved]

Subpart B—Monitoring Provisions

§ 75.10 General operating requirements.

- (a) **Primary Measurement Requirement.** The owner or operator shall measure opacity, and all SO₂, NO_x, and CO₂ emissions for each affected unit as follows:

- (1) To determine SO₂ emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO₂ continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO₂ concentration (in ppm), volumetric gas flow (in scfh), and SO₂ mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§ 75.11 and 75.16 and subpart E of this part;
- (2) To determine NO_x emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a NO_x-diluent continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor and an O₂ or CO₂ diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NO_x concentration (in ppm), O₂ or CO₂ concentration (in percent O₂ or CO₂) and NO_x emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in §§ 75.12 and 75.17 and subpart E of this part. The owner or operator shall account for total NO_x emissions, both NO and NO₂, either by monitoring for both NO and NO₂ or by monitoring for NO only and adjusting the emissions data to account for NO₂;
- (3) The owner or operator shall determine CO₂ emissions by using one of the following options, except as provided in § 75.13 and subpart E of this part:
 - (i) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a CO₂ continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording CO₂ concentration (in ppm or percent), volumetric gas flow (in scfh), and CO₂ mass emissions (in tons/hr) discharged to the atmosphere;
 - (ii) The owner or operator shall determine CO₂ emissions based on the measured carbon content of the fuel and the procedures in appendix G of this part to estimate CO₂ emissions (in ton/day) discharged to the atmosphere; or
 - (iii) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a flow monitoring system and a CO₂ continuous emission monitoring system that uses an O₂ concentration monitor to determine CO₂ emissions (according to the procedures in appendix F of this part) with an automated data acquisition and handling system for measuring and recording O₂ concentration (in percent), CO₂ concentration (in percent), volumetric gas flow (in scfh), and CO₂ mass emissions (in tons/hr) discharged to the atmosphere;
- (4) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements in this part, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) discharged to the atmosphere, except as provided in §§ 75.14 and 75.18; and
- (5) A single certified flow monitoring system may be used to meet the requirements of paragraphs (a)(1) and (a)(3) of this section. A single certified diluent monitor may be used to meet the requirements of paragraphs (a)(2) and (a)(3) of this section. A single automated data acquisition and handling system may be used to meet the requirements of paragraphs (a)(1) through (a)(4) of this section.

- (b) **Primary Equipment Performance Requirements.** The owner or operator shall ensure that each continuous emission monitoring system required by this part meets the equipment, installation, and performance specifications in appendix A to this part; and is maintained according to the quality assurance and quality control procedures in appendix B to this part; and shall record SO₂ and NO_x emissions in the appropriate units of measurement (i.e., lb/hr for SO₂ and lb/mmBtu for NO_x).
- (c) **Heat Input Rate Measurement Requirement.** The owner or operator shall determine and record the heat input rate, in units of mmBtu/hr, to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in appendix F to this part.
- (d) **Primary equipment hourly operating requirements.** The owner or operator shall ensure that all continuous emission and opacity monitoring systems required by this part are in operation and monitoring unit emissions or opacity at all times that the affected unit combusts any fuel except as provided in § 75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to § 75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to § 75.20. The owner or operator shall also ensure, subject to the exceptions above in this paragraph, that all continuous opacity monitoring systems required by this part are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable Federal, State, or local regulation, or permit. The owner or operator shall ensure that the following requirements are met:
 - (1) The owner or operator shall ensure that each continuous emission monitoring system is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO₂ concentrations, volumetric flow, SO₂ mass emissions, CO₂ concentration, O₂ concentration, CO₂ mass emissions (if applicable), NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to § 75.21 and appendix B of this part, or backups of data from the data acquisition and handling system, or recertification, pursuant to § 75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.
 - (2) The owner or operator shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. The owner or operator shall reduce all opacity data to 6-min averages calculated in accordance with the provisions of part 51, appendix M of this chapter, except where the applicable State implementation plan or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement.
 - (3) Failure of an SO₂, CO₂, or O₂ emissions concentration monitor, NO_x concentration monitor, flow monitor, moisture monitor, or NO_x-diluent continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. For a NO_x-diluent monitoring system, an hourly average NO_x emission rate in lb/

mmBtu is valid only if the minimum number of data points is acquired by both the NO_x pollutant concentration monitor and the diluent monitor (O₂ or CO₂). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O₂ on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.

- (e) **Optional backup monitor requirements.** If the owner or operator chooses to use two or more continuous emission monitoring systems, each of which is capable of monitoring the same stack or duct at a specific affected unit, or group of units using a common stack, then the owner or operator shall designate one monitoring system as the primary monitoring system, and shall record this information in the monitoring plan, as provided for in § 75.53. The owner or operator shall designate the other monitoring system(s) as backup monitoring system(s) in the monitoring plan. The backup monitoring system(s) shall be designated as redundant backup monitoring system(s), non-redundant backup monitoring system(s), or reference method backup system(s), as described in § 75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in § 75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from the backup monitoring system may be reported as valid, quality-assured data only when the backup is operating and not out-of-control as defined in § 75.24 (or in the applicable reference method in appendix A of part 60 of this chapter) and when the certified primary monitoring system is not operating (or is operating but out-of-control). A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.
- (f) **Minimum measurement capability requirement.** The owner or operator shall ensure that each continuous emission monitoring system is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to this part.
- (g) **Minimum recording and recordkeeping requirements.** The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of this part as specified in subparts F and G of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26519, May 17, 1995; 64 FR 28590, May 26, 1999; 67 FR 40422, June 12, 2002; 70 FR 28678, May 18, 2005; 76 FR 17308, Mar. 28, 2011]

§ 75.11 Specific provisions for monitoring SO₂ emissions.

- (a) **Coal-fired units.** The owner or operator shall meet the general operating requirements in § 75.10 for an SO₂ continuous emission monitoring system and a flow monitoring system for each affected coal-fired unit while the unit is combusting coal and/or any other fuel, except as provided in paragraph (e) of this section, in § 75.16, and in subpart E of this part. During hours in which only gaseous fuel is combusted in the unit, the owner or operator shall comply with the applicable provisions of paragraph (e)(1), (e)(2), or (e)(3) of this section.
- (b) **Moisture correction.** Where SO₂ concentration is measured on a dry basis, the owner or operator shall either:

- (1) Report the appropriate fuel-specific default moisture value for each unit operating hour, selected from among the following: 3.0%, for anthracite coal; 6.0% for bituminous coal; 8.0% for sub-bituminous coal; 11.0% for lignite coal; 13.0% for wood and 14.0% for natural gas (boilers, only); or
 - (2) 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 SO₂ mass emissions (in lb/hr) using the procedures in appendix F to this part. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O₂ 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 O₂ 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.
- (c) **Unit with no location for a flow monitor meeting siting requirements.** Where no location exists that satisfies the minimum physical siting criteria in appendix A to this part for installation of a flow monitor in either the stack or the ducts serving an affected unit or installation of a flow monitor in either the stack or ducts is demonstrated to the satisfaction of the Administrator to be technically infeasible, either:
- (1) The designated representative shall petition the Administrator for an alternative method for monitoring volumetric flow in accordance with § 75.66; or
 - (2) The owner or operator shall construct a new stack or modify existing ductwork to accommodate the installation of a flow monitor, and the designated representative shall petition the Administrator for an extension of the required certification date given in § 75.4 and approval of an interim alternative flow monitoring methodology in accordance with § 75.66. The Administrator may grant existing Phase I affected units an extension to January 1, 1995, and existing Phase II affected units an extension to January 1, 1996 for the submission of the certification application for the purpose of constructing a new stack or making substantial modifications to ductwork for installation of a flow monitor; or
 - (3) The owner or operator shall install a flow monitor in any existing location in the stack or ducts serving the affected unit at which the monitor can achieve the performance specifications of this part.
- (d) **Gas-fired and oil-fired units.** The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall measure and record SO₂ emissions:
- (1) By meeting the general operating requirements in § 75.10 for an SO₂ continuous emission monitoring system and flow monitoring system. If this option is selected, the owner or operator shall comply with the applicable provisions in paragraph (e)(1), (e)(2), or (e)(3) of this section during hours in which the unit combusts only gaseous fuel;
 - (2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D to this part for estimating hourly SO₂ mass emissions; or

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO₂ mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b). If this option is selected for SO₂, the LME methodology must also be used for NO_x and CO₂ when these parameters are required to be monitored by applicable program(s).

(e) **Special considerations during the combustion of gaseous fuels.** The owner or operator of an affected unit that uses a certified flow monitor and a certified diluent gas (O₂ or CO₂) monitor to measure the unit heat input rate shall, during any hours in which the unit combusts only gaseous fuel, determine SO₂ emissions in accordance with paragraph (e)(1) or (e)(3) of this section, as applicable.

(1) If the gaseous fuel qualifies for a default SO₂ emission rate under Section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, the owner or operator may determine SO₂ emissions by using Equation F-23 in appendix F to this part. Substitute into Equation F-23 the hourly heat input, calculated using the certified flow monitoring system and the certified diluent monitor (according to the applicable equation in section 5.2 of appendix F to this part), in conjunction with the appropriate default SO₂ emission rate from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under § 75.20(c), and shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor; or

(2) [Reserved]

(3) The owner or operator may determine SO₂ mass emissions by using a certified SO₂ continuous monitoring system, in conjunction with the certified flow rate monitoring system. However, if the gaseous fuel is very low sulfur fuel (as defined in § 72.2 of this chapter), the SO₂ monitoring system shall meet the following quality assurance provisions when the very low sulfur fuel is combusted:

(i) When conducting the daily calibration error tests of the SO₂ monitoring system, as required by section 2.1.1 in appendix B of this part, the zero-level calibration gas shall have an SO₂ concentration of 0.0 percent of span. This restriction does not apply if gaseous fuel is burned in the affected unit only during unit startup.

(ii) EPA recommends that the calibration response of the SO₂ monitoring system be adjusted, either automatically or manually, in accordance with the procedures for routine calibration adjustments in section 2.1.3 of appendix B to this part, whenever the zero-level calibration response during a required daily calibration error test exceeds the applicable performance specification of the instrument in section 3.1 of appendix A to this part (i.e., ±2.5 percent of the span value or ±5 ppm, whichever is less restrictive).

(iii) Any bias-adjusted hourly average SO₂ concentration of less than 2.0 ppm recorded by the SO₂ monitoring system shall be adjusted to a default value of 2.0 ppm, for reporting purposes. Such adjusted hourly averages shall be considered to be quality-assured data, provided that the monitoring system is operating and is not out-of-control with respect to any of the quality assurance tests required by appendix B of this part (i.e., daily calibration error, linearity and relative accuracy test audit).

(iv) In accordance with the requirements of section 2.1.1.2 of appendix A to this part, for units that sometimes burn gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) and at other times burn higher sulfur fuel(s) such as coal or oil, a second low-scale SO₂ measurement range is not required when the very low sulfur gaseous fuel is combusted. For

units that burn only gaseous fuel that is very low sulfur fuel and burn no other type(s) of fuel(s), the owner or operator shall set the span of the SO₂ monitoring system to a value no greater than 200 ppm.

(4) The provisions in paragraph (e)(1) of this section, may also be used for the combustion of a solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, mixtures of such fuels, or combinations of such fuels with gaseous fuel, if the owner or operator submits a petition under § 75.66 for a default SO₂ emission rate for each fuel, mixture or combination, and if the Administrator approves the petition.

(f) **Other units.** The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions for coal-fired units specified in paragraph (a) of this section, except where the owner or operator has an approved petition to use the provisions of paragraph (e)(1) of this section.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26520, 26566, May 17, 1995; 61 FR 59157, Nov. 20, 1996; 63 FR 57499, Oct. 27, 1998; 64 FR 28590, May 26, 1999; 67 FR 40423, June 12, 2002; 73 FR 4342, Jan. 24, 2008]

§ 75.12 Specific provisions for monitoring NO_x emission rate.

(a) **Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units.** The owner or operator shall meet the general operating requirements in § 75.10 of this part for a NO_x continuous emission monitoring system (CEMS) for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (d) of this section, § 75.17, and subpart E of this part. The diluent gas monitor in the NO_x-diluent CEMS may measure either O₂ or CO₂ concentration in the flue gases.

(b) **Moisture correction.** If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu, e.g., if the NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor, the owner or operator shall either report a fuel-specific default moisture value for each unit operating hour, as provided in § 75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b)(2). Notwithstanding this requirement, if Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to measure NO_x emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in § 75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; 15.0% for wood and 18.0% for natural gas (boilers, only).

(c) **Determination of NO_x emission rate.** The owner or operator shall calculate hourly, quarterly, and annual NO_x emission rates (in lb/mmBtu) by combining the NO_x concentration (in ppm), diluent concentration (in percent O₂ or CO₂), and percent moisture (if applicable) measurements according to the procedures in appendix F to this part.

(d) **Gas-fired peaking units or oil-fired peaking units.** The owner or operator of an affected unit that qualifies as a gas-fired peaking unit or oil-fired peaking unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_x continuous emission monitoring system; or

- (2) Provide information satisfactory to the Administrator using the procedure specified in appendix E of this part for estimating hourly NO_x emission rate. However, if in the years after certification of an excepted monitoring system under appendix E of this part, a unit's operations exceed a capacity factor of 20 percent in any calendar year or exceed a capacity factor of 10.0 percent averaged over three years, the owner or operator shall install, certify, and operate a NO_x-diluent continuous emission monitoring system no later than December 31 of the following calendar year. If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_x emission rate (MER) (as defined in § 72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified.
- (e) **Low mass emissions units.** Notwithstanding the requirements of paragraphs (a) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:
 - (1) Meet the general operating requirements in § 75.10 for a NO_x continuous emission monitoring system;
 - (2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or
 - (3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_x emission rate and hourly NO_x mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for NO_x, the LME methodology must also be used for SO₂ and CO₂ when these parameters are required to be monitored by applicable program(s).
- (f) **Other units.** The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions specified in paragraph (a) of this section.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26520, May 17, 1995; 63 FR 57499, Oct. 27, 1998; 64 FR 28591, May 26, 1999; 67 FR 40423, June 12, 2002; 73 FR 4342, Jan. 24, 2008]

§ 75.13 Specific provisions for monitoring CO₂ emissions.

- (a) **CO₂ continuous emission monitoring system.** If the owner or operator chooses to use the continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in § 75.10 for a CO₂ continuous emission monitoring system and flow monitoring system for each affected unit. The owner or operator shall comply with the applicable provisions specified in §§ 75.11(a) through (e) or § 75.16, except that the phrase "CO₂ continuous emission monitoring system" shall apply rather than "SO₂ continuous emission monitoring system," the phrase "CO₂ concentration" shall apply rather than "SO₂ concentration," the term "maximum potential concentration of CO₂" shall apply rather than "maximum potential concentration of SO₂," and the phrase "CO₂ mass emissions" shall apply rather than "SO₂ mass emissions."
- (b) **Determination of CO₂ emissions using appendix G to this part.** If the owner or operator chooses to use the appendix G method, then the owner or operator shall follow the procedures in appendix G to this part for estimating daily CO₂ mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO₂, the owner or operator shall use the procedures in appendix G to this part to estimate both combustion-related emissions based on the measured carbon content of the fuel and the

amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO₂ mass emissions (in tons) in accordance with the procedures in appendix G to this part.

- (c) **Determination of CO₂ mass emissions using an O₂ monitor according to appendix F to this part.** If the owner or operator chooses to use the appendix F method, then the owner or operator shall determine hourly CO₂ concentration and mass emissions with a flow monitoring system; a continuous O₂ concentration monitor; fuel F and F_c factors; and, where O₂ concentration is measured on a dry basis (or where Equation F-14b in appendix F to this part is used to determine CO₂ concentration), either, a continuous moisture monitoring system, as specified in § 75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in § 75.11(b)(1); and by using the methods and procedures specified in appendix F to this part. For units using a common stack, multiple stack, or bypass stack, the owner or operator may use the provisions of § 75.16, except that the phrase "CO₂ continuous emission monitoring system" shall apply rather than "SO₂ continuous emission monitoring system," the term "maximum potential concentration of CO₂" shall apply rather than "maximum potential concentration of SO₂," and the phrase "CO₂ mass emissions" shall apply rather than "SO₂ mass emissions."
- (d) **Determination of CO₂ mass emissions from low mass emissions units.** The owner or operator of a unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:
- (1) Meet the general operating requirements in § 75.10 for a CO₂ continuous emission monitoring system and flow monitoring system;
 - (2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or
 - (3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO₂ mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for CO₂, the LME methodology must also be used for NO_x and SO₂ when these parameters are required to be monitored by applicable program(s).

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26521, May 17, 1995; 63 FR 57499, Oct. 27, 1998; 64 FR 28591, May 26, 1999; 67 FR 40423, June 12, 2002; 73 FR 4343, Jan. 24, 2008]

§ 75.14 Specific provisions for monitoring opacity.

- (a) **Coal-fired units and oil-fired units.** The owner or operator shall meet the general operating provisions in § 75.10 of this part for a continuous opacity monitoring system for each affected coal-fired or oil-fired unit, except as provided in paragraphs (b), (c), and (d) of this section and in § 75.18. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specification 1 in appendix B to part 60 of this chapter. Any continuous opacity monitoring system previously certified to meet Performance Specification 1 shall be deemed certified for the purposes of this part.
- (b) **Unit with wet flue gas pollution control system.** If the owner or operator can demonstrate that condensed water is present in the exhaust flue gas stream and would impede the accuracy of opacity measurements, then the owner or operator of an affected unit equipped with a wet flue gas pollution control system for SO₂ emissions or particulates is exempt from the opacity monitoring requirements of this part.

- (c) **Gas-fired units.** The owner or operator of an affected unit that qualifies as gas-fired, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan is exempt from the opacity monitoring requirements of this part. Whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system as required by paragraph (a) of this section by December 31 of the following calendar year.
- (d) **Diesel-fired units and dual-fuel reciprocating engine units.** The owner or operator of an affected diesel-fired unit or a dual-fuel reciprocating engine unit is exempt from the opacity monitoring requirements of this part.
- (e) Unit with a certified particulate matter (PM) monitoring system. If, for a particular affected unit, the owner or operator installs, certifies, operates, maintains, and quality-assures a continuous particulate matter (PM) monitoring system in accordance with Procedure 2 in appendix F to part 60 of this chapter, the unit shall be exempt from the opacity monitoring requirement of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 61 FR 25581, May 22, 1996; 73 FR 4343, Jan. 24, 2008]

§ 75.15 [Reserved]

§ 75.16 Special provisions for monitoring emissions from common, bypass, and multiple stacks for SO₂ emissions and heat input determinations.

- (a) [Reserved]
- (b) **Common stack procedures.** The following procedures shall be used when more than one unit uses a common stack:
 - (1) **Unit utilizing common stack with other affected unit(s).** When a Phase I or Phase II affected unit utilizes a common stack with one or more other Phase I or Phase II affected units, but no nonaffected units, the owner or operator shall either:
 - (i) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in the duct to the common stack from each affected unit; or
 - (ii) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in the common stack and combine emissions for the affected units for recordkeeping and compliance purposes.
 - (2) **Unit utilizing common stack with nonaffected unit(s).** When one or more Phase I or Phase II affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:
 - (i) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in the duct to the common stack from each Phase I and Phase II unit; or
 - (ii) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in the common stack; and
 - (A) Designate the nonaffected units as opt-in units in accordance with part 74 of this chapter and combine emissions for recordkeeping and compliance purposes; or

- (B) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in the duct from each nonaffected unit; determine SO₂ mass emissions from the affected units as the difference between SO₂ mass emissions measured in the common stack and SO₂ mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly average value less than zero; combine emissions for the Phase I and Phase II affected units for recordkeeping and compliance purposes; and calculate and report SO₂ mass emissions from the Phase I and Phase II affected units, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated; or
 - (C) Record the combined emissions from all units as the combined SO₂ mass emissions for the Phase I and Phase II affected units for recordkeeping and compliance purposes; or
 - (D) Petition through the designated representative and provide information satisfactory to the Administrator on methods for apportioning SO₂ mass emissions measured in the common stack to each of the units using the common stack and on reporting the SO₂ mass emissions. The Administrator may approve such demonstrated substitute methods for apportioning and reporting SO₂ mass emissions measured in a common stack whenever the demonstration ensures that there is a complete and accurate accounting of all emissions regulated under this part and, in particular, that the emissions from any affected unit are not underestimated.
- (c) **Unit with bypass stack.** Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack so as to avoid the installed SO₂ continuous emission monitoring system and flow monitoring system, the owner or operator shall either:
- (1) Install, certify, operate, and maintain separate SO₂ continuous emission monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate SO₂ mass emissions for the unit as the sum of the SO₂ mass emissions measured at the two stacks; or
 - (2) Monitor SO₂ mass emissions at the main stack using SO₂ and flow rate monitoring systems and measure SO₂ mass emissions at the bypass stack using the reference methods in § 75.22(b) for SO₂ and flow rate and calculate SO₂ mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or
 - (3) Install, certify, operate, and maintain SO₂ and flow rate monitoring systems only on the main stack. If this option is chosen, report the following values for each hour during which emissions pass through the bypass stack: the maximum potential concentration of SO₂ as determined under section 2.1.1.1 of appendix A to this part (or, if available, the SO₂ concentration measured by a certified monitor located at the control device inlet may be reported instead), and the hourly volumetric flow rate value that would be substituted for the flow monitor installed on the main stack or flue under the missing data procedures in subpart D of this part if data from the flow monitor installed on the main stack or flue were missing for the hour. The maximum potential SO₂ concentration may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(b)(5)). The option in this paragraph, (c)(3), may only be used if use of the bypass stack is limited to unit startup, emergency situations (e.g., malfunction of a flue gas desulfurization system), and periods of routine maintenance of the flue gas desulfurization system or maintenance on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, with respect to SO₂ or any other

parameter that is monitored only at the main stack. Calculate SO₂ mass emissions for the unit as the sum of the emissions calculated with the substitute values and the emissions recorded by the SO₂ and flow monitoring systems installed on the main stack.

- (d) **Unit with multiple stacks or ducts.** When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (that may include flue gases from other affected or nonaffected units), or when the flue gases utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than the stack, the owner or operator shall either:
- (1) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in each duct feeding into the stack or stacks and determine SO₂ mass emissions from each affected unit as the sum of the SO₂ mass emissions recorded for each duct; or
 - (2) Install, certify, operate, and maintain an SO₂ continuous emission monitoring system and flow monitoring system in each stack. Determine SO₂ mass emissions from each affected unit as the sum of the SO₂ mass emissions recorded for each stack. Notwithstanding the prior sentence, if another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable common stack requirements of this section to determine and record SO₂ mass emissions from the units using that stack and shall calculate and report SO₂ mass emissions from the affected units and stacks, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated.
- (e) **Heat input rate.** The owner or operator of an affected unit using a common stack, bypass stack, or multiple stacks shall account for heat input rate according to the following:
- (1) The owner or operator of an affected unit using a common stack, bypass stack, or multiple stack with a diluent monitor and a flow monitor on each stack may use the flow rate and diluent monitors to determine the heat input rate for the affected unit, using the procedures specified in paragraphs (b) through (d) of this section, except that the term "heat input rate" shall apply rather than "SO₂ mass emissions" or "emissions" and the phrase "a diluent monitor and a flow monitor" shall apply rather than "SO₂ continuous emission monitoring system and flow monitoring system." The applicable equation in appendix F to this part shall be used to calculate the heat input rate from the hourly flow rate, diluent monitor measurements, and (if the equation in appendix F requires a correction for the stack gas moisture content) hourly moisture measurements. Notwithstanding the options for combining heat input rate in paragraph (b)(1)(ii) and (b)(2)(ii) of this section, the owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine the combined heat input rate at the common stack shall also determine and report heat input rate to each individual unit, according to paragraph (e)(3) of this section.
 - (2) In the event that an owner or operator of a unit with a bypass stack does not install and certify a diluent monitor and flow monitoring system in a bypass stack, the owner or operator shall determine total heat input rate to the unit for each unit operating hour during which the bypass stack is used according to the missing data provisions for heat input rate under § 75.36 or the procedures for calculating heat input rate from fuel sampling and analysis in section 5.5 of appendix F to this part.
 - (3) The owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine heat input rate at the common stack may choose to apportion the heat input rate from the common stack to each affected unit utilizing the common stack by using either of the following two methods, provided that all of the units utilizing the common stack are combusting fuel with the same F-factor found in section 3 of appendix F of this part. The heat input rate may be apportioned either by using the ratio of load (in MWe) for each individual unit to the total

load for all units utilizing the common stack or by using the ratio of steam load (in 1000 lb/hr or mmBtu/hr thermal output) for each individual unit to the total steam load for all units utilizing the common stack, in conjunction with the appropriate unit and stack operating times. If using either of these apportionment methods, the owner or operator shall apportion according to section 5.6 of appendix F to this part.

- (4) Notwithstanding paragraph (e)(1) of this section, any affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_x mass emission reduction program must also meet the requirements for monitoring heat input rate in §§ 75.71, 75.72 and 75.75.

[60 FR 26522, May 17, 1995, as amended at 61 FR 25582, May 22, 1996; 61 FR 59158, Nov. 20, 1996; 64 FR 28591, May 26, 1999; 67 FR 40423, June 12, 2002; 67 FR 53504, Aug. 16, 2002; 73 FR 4343, Jan. 24, 2008]

§ 75.17 Specific provisions for monitoring emissions from common, bypass, and multiple stacks for NO_x emission rate.

Notwithstanding the provisions of paragraphs (a), (b), (c), and (d) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_x mass emission reduction program must also meet the provisions for monitoring NO_x emission rate in §§ 75.71 and 75.72.

- (a) **Unit utilizing common stack with other affected unit(s).** When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:
- (1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the duct to the common stack from each affected unit; or
 - (2) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the common stack and follow the appropriate procedure in paragraphs (a)(2) (i) through (iii) of this section, depending on whether or not the units are required to comply with a NO_x emission limitation (in lb/mmBtu, annual average basis) pursuant to section 407(b) of the Act (referred to hereafter as "NO_x emission limitation").
 - (i) When each of the affected units has a NO_x emission limitation, the designated representative shall submit a compliance plan to the Administrator that indicates:
 - (A) Each unit will comply with the most stringent NO_x emission limitation of any unit utilizing the common stack; or
 - (B) Each unit will comply with the applicable NO_x emission limitation by averaging its emissions with the other unit(s) utilizing the common stack, pursuant to the emissions averaging plan submitted under part 76 of this chapter; or
 - (C) Each unit's compliance with the applicable NO_x emission limit will be determined by a method satisfactory to the Administrator for apportioning to each of the units the combined NO_x emission rate (in lb/mmBtu) measured in the common stack and for reporting the NO_x emission rate, as provided in a petition submitted by the designated representative. The Administrator may approve such demonstrated substitute methods for apportioning and reporting NO_x emission rate measured in a common stack whenever

the demonstration ensures that there is a complete and accurate estimation of all emissions regulated under this part and, in particular, that the emissions from any unit with a NO_x emission limitation are not underestimated.

(ii) When none of the affected units has a NO_x emission limitation, the owner or operator and the designated representative have no additional obligations pursuant to section 407 of the Act and may record and report a combined NO_x emission rate (in lb/mmBtu) for the affected units utilizing the common stack.

(iii) When at least one of the affected units has a NO_x emission limitation and at least one of the affected units does not have a NO_x emission limitation, the owner or operator shall either:

(A) Install, certify, operate, and maintain NO_x and diluent monitors in the ducts from the affected units; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack on each of the units. The Administrator may approve such demonstrated substitute methods for apportioning the combined NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(b) **Unit utilizing common stack with nonaffected unit(s).** When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system in the duct from each affected unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack for each of the units. The Administrator may approve such demonstrated substitute methods for apportioning the combined NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(c) **Unit with multiple stacks or ducts.** When the flue gases from an affected unit discharge to the atmosphere through two or more stacks or when flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than the stack, the owner or operator shall monitor the NO_x emission rate in a way that is representative of each affected unit. Where another unit also exhausts flue gases to one or more of the stacks where monitoring systems are installed, the owner or operator shall also comply with the applicable common stack monitoring requirements of this section. The owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system and a flow monitoring system in each stack or duct and determine the NO_x emission rate for the unit as the Btu-weighted average of the NO_x emission rates measured in the stacks or ducts using the heat input estimation procedures in appendix F to this part. Alternatively, for units that are eligible to use the procedures of appendix D to this part, the owner or operator may monitor heat input and NO_x emission rate at the unit level, in lieu of installing flow monitors on each stack or duct. If this alternative unit-level monitoring is performed, report, for each unit operating hour, the highest emission rate measured by any of the NO_x-diluent monitoring systems installed on the individual stacks or ducts as the hourly NO_x emission rate for the unit, and report the hourly unit heat input as determined under appendix D to this part. Also, when this alternative unit-level monitoring is

performed, the applicable NO_x missing data procedures in §§ 75.31 or 75.33 shall be used for each unit operating hour in which a quality-assured NO_x emission rate is not obtained for one or more of the individual stacks or ducts; or

- (2) Provided that the products of combustion are well-mixed, install, certify, operate, and maintain a NO_x continuous emission monitoring system in one stack or duct from the affected unit and record the monitored value as the NO_x emission rate for the unit. The owner or operator shall account for NO_x emissions from the unit during all times when the unit combusts fuel. Therefore, this option shall not be used if the monitored stack or duct can be bypassed (e.g., by using dampers). Follow the procedure in § 75.17(d) for units with bypass stacks. Further, this option shall not be used unless the monitored NO_x emission rate truly represents the NO_x emissions discharged to the atmosphere (e.g., the option is disallowed if there are any additional NO_x emission controls downstream of the monitored location).

(d) **Unit with a main stack and bypass stack configuration.** For an affected unit with a discharge configuration consisting of a main stack and a bypass stack, the owner or operator shall either:

- (1) Follow the procedures in paragraph (c)(1) of this section; or
- (2) Install, certify, operate, and maintain a NO_x-diluent CEMS only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, with respect to NO_x or any other parameter that is monitored only at the main stack. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report the maximum potential NO_x emission rate (as defined in § 72.2 of this chapter). The maximum potential NO_x emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). Alternatively, for a unit with NO_x add-on emission controls, for each unit operating hour in which the bypass stack is used and the add-on NO_x emission controls are not bypassed, the owner or operator may report the maximum controlled NO_x emission rate (MCR) instead of the maximum potential NO_x emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_x add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part where the words "maximum potential NO_x emission rate (MER)" shall apply instead of the words "maximum controlled NO_x emission rate (MCR)" and by using the NO_x MEC in the calculations instead of the NO_x MPC.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26523, May 17, 1995; 63 FR 57499, Oct. 27, 1998; 64 FR 28592, May 26, 1999; 67 FR 40424, June 12, 2002; 73 FR 4343, Jan. 24, 2008]

§ 75.18 Specific provisions for monitoring emissions from common and by-pass stacks for opacity.

- (a) **Unit using common stack.** When an affected unit utilizes a common stack with other affected units or nonaffected units, the owner or operator shall comply with the applicable monitoring provision in this paragraph, as determined by existing Federal, State, or local opacity regulations.

- (1) Where another regulation requires the installation of a continuous opacity monitoring system upon each affected unit, the owner or operator shall install, certify, operate, and maintain a continuous opacity monitoring system meeting Performance Specification 1 in appendix B to part 60 of this chapter (referred to hereafter as a "certified continuous opacity monitoring system") upon each unit.
- (2) Where another regulation does not require the installation of a continuous opacity monitoring system upon each affected unit, and where the affected source is not subject to any existing Federal, State, or local opacity regulations, the owner or operator shall install, certify, operate, and maintain a certified continuous opacity monitoring system upon each common stack for the combined effluent.
- (b) **Unit using bypass stack.** Where any portion of the flue gases from an affected unit can be routed so as to bypass the installed continuous opacity monitoring system, the owner or operator shall install, certify, operate, and maintain a certified continuous opacity monitoring system on each bypass stack flue, duct, or stack gas stream unless either:
 - (1) An applicable Federal, State, or local opacity regulation or permit exempts the unit from a requirement to install a continuous opacity monitoring system in the bypass stack; or
 - (2) A continuous opacity monitoring system is already installed and certified at the inlet of the add-on emissions controls.
 - (3) The owner or operator monitors opacity using method 9 of appendix A of part 60 of this chapter whenever emissions pass through the bypass stack. Method 9 shall be used in accordance with the applicable State regulations.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26524, May 17, 1995; 60 FR 40296, Aug. 8, 1995; 61 FR 59158, Nov. 20, 1996]

§ 75.19 Optional SO₂, NO_x, and CO₂ emissions calculation for low mass emissions (LME) units.

(a) **Applicability and qualification.**

- (1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions (LME) excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of methods under appendices D, E, and G to this part, for the purpose of determining unit heat input, NO_x, SO₂, and CO₂ mass emissions, and NO_x emission rate under this part. If the owner or operator of a qualifying unit elects to use the LME methodology, it must be used for all parameters that are required to be monitored by the applicable program(s). For example, for an Acid Rain Program LME unit, the methodology must be used to estimate SO₂, NO_x, and CO₂ mass emissions, NO_x emission rate, and unit heat input.
 - (i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired (as defined in § 72.2 of this chapter), and for which:
 - (A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits:
 - (1) No more than 25 tons of SO₂ annually and less than 100 tons of NO_x annually, for Acid Rain Program affected units. If the unit is also subject to the provisions of subpart H of this part, no more than 50 of the allowable annual tons of NO_x may be emitted during the ozone season; or

- (2) Less than 100 tons of NO_x annually *and* no more than 50 tons of NO_x during the ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data on a year-round basis, in accordance with § 75.74(a) or § 75.74(b); or
 - (3) No more than 50 tons of NO_x per ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data only during the ozone season, in accordance with § 75.74(b); and
 - (B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emissions unit continues to emit no more than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section.
 - (C) This paragraph, (a)(1)(i)(C), applies only to a unit that is subject to an SO₂ emission limitation under the Acid Rain Program, and that combusts a gaseous fuel other than pipeline natural gas or natural gas (as defined in § 72.2 of this chapter). The owner or operator of such a unit must quantify the sulfur content and variability of the gaseous fuel by performing the demonstration described in section 2.3.6 of appendix D to this part, in order for the unit to qualify for LME unit status. If the results of that demonstration show that the gaseous fuel qualifies under paragraph (b) of section 2.3.6 to use a default SO₂ emission rate to report SO₂ mass emissions under this part, the unit is eligible for LME unit status.
- (ii) Each qualifying LME unit must start using the low mass emissions excepted methodology as follows:
- (A) For a unit that reports emission data on a year-round basis, begin using the methodology in the first unit operating hour in the calendar year designated in the certification application as the first year that the methodology will be used; or
 - (B) For a unit that is subject to Subpart H of this part and that reports only during the ozone season according to § 75.74(c), begin using the methodology in the first unit operating hour in the ozone season designated in the certification application as the first ozone season that the methodology will be used.
 - (C) For a new or newly-affected unit, see paragraph (b)(4) of this section for additional guidance.
- (2) A unit may initially qualify as a low mass emissions unit if the designated representative submits a certification application to use the LME methodology (as described in § 75.63(a)(1)(ii) and in this paragraph, (a)(2)) and the Administrator (or permitting authority, as applicable) certifies the use of such methodology. The certification application shall be submitted no later than 45 days prior to the date on which use of the low mass emissions methodology is expected to commence, and the application must contain:
- (i) A statement identifying the projected date on which the LME methodology will first be used. The projected commencement date shall be consistent with paragraphs (a)(1)(ii) and (b)(4) of this section, as applicable; and
 - (ii) Either:

- (A) Actual SO₂ and/or NO_x mass emissions data (as applicable) for each of the three calendar years (or ozone seasons) prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator or (if applicable) the permitting authority, that the unit emitted less than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section. For the purposes of this paragraph, (a)(2)(ii)(A), the required actual SO₂ or NO_x mass emissions for each qualifying year or ozone season shall be determined using the SO₂, NO_x and heat input data reported to the Administrator in the electronic quarterly reports required under § 75.64 or under the Ozone Transport Commission (OTC) NO_x Budget Trading Program. Notwithstanding this requirement, in the absence of such electronic reports, an estimate of the actual emissions for each of the previous three years (or ozone seasons) shall be provided, using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or procedures consistent with the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO₂ or NO_x emission rate from paragraph (c)(1)(i) of this section for SO₂, and paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_x. Alternatively, the initial estimate of the NO_x emission rate may be based on historical emission test data that is representative of operation at normal load or historical data from a CEMS certified under part 60 of this chapter or under a state CEM program; or
- (B) When the three full years (or ozone seasons) of actual SO₂ and NO_x mass emissions data (or reliable estimates thereof) described under paragraph (a)(2)(ii)(A) of this section do not exist, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of actual historical SO₂ and NO_x mass emissions data and projected SO₂ and NO_x mass emissions, totaling three years (or ozone seasons). Except as provided in paragraph (a)(3) of this section, actual data must be used for any years (or ozone seasons) in which such data exists and projected data should be used for any remaining future years (or ozone seasons) needed to provide emissions data for three consecutive calendar years (or ozone seasons). For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for a new unit, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section. Projected emissions shall be calculated using either the appropriate default emission rates from paragraphs (c)(1)(i) and (c)(1)(ii) of this section (or, alternatively for NO_x, a conservative estimate of the NO_x emission rate, as described in paragraph (a)(4) of this section), in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section; and
- (iii) A description of the methodology from paragraph (c) of this section that will be used to demonstrate on-going compliance under paragraph (b) of this section; and
- (iv) Appropriate documentation demonstrating that the unit is eligible to use projected emissions to qualify for LME status under paragraph (a)(3) of this section (if applicable).

- (3) In the following circumstances, projected emissions for a future year (or years) may be used in lieu of the actual emissions data from one (or more) of the three years (or ozone seasons) preceding the year of the certification application:
- (i) If the owner or operator takes an enforceable permit restriction on the number of annual or ozone season unit operating hours for the future year (or years), such that the unit will emit no more than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section; or
 - (ii) If the actual emissions for one (or more) of the three years (or ozone seasons) prior to the year of the certification application is not representative of the present and expected future emissions from the unit, because the owner or operator has recently installed emission controls on the unit.
- (4) When the owner or operator elects to demonstrate initial LME qualification and on-going compliance using a fuel-and-unit-specific NO_x emission rate in accordance with paragraph (c)(1)(iv) of this section, there will be instances (e.g., for a new or newly-affected unit) where it is not possible to determine that NO_x emission rate prior to submitting the certification application. In such cases, if the generic default NO_x emission rates in Table LM-2 of this section are inappropriately high for the unit, the owner or operator may use a more representative, but conservatively high estimate of the expected NO_x emission rate, for the purposes of the initial monitoring plan submittal and to calculate the unit's projected annual or ozone season emissions under paragraph (a)(2)(ii)(B) of this section. For example, the NO_x emission rate could, as described in paragraph (a)(2)(ii)(A) of this section, be estimated using historical CEM data or historical emission test data that is representative of operation at normal load. The NO_x emission limit specified in the operating permit for the unit could also be used to estimate the NO_x emission rate (except for units equipped with SCR or SNCR), or, consistent with paragraph (c)(1)(iv)(C)(4) of this section, for a unit that uses SCR or SNCR to control NO_x emissions, an estimated default NO_x emission rate of 0.15 lb/mmBtu could be used. However, these estimated NO_x emission rates may not be used for reporting purposes in the time period extending from the first hour in which the LME methodology is used to the date and hour on which the fuel-and-unit-specific NO_x emission rate testing is completed. Rather, in that interval, the owner or operator shall either report the appropriate default NO_x emission rate from Table LM-2, or shall report the maximum potential NO_x emission rate, calculated in accordance with § 72.2 of this chapter and section 2.1.2.1 of appendix A to this part. Then, beginning with the first unit operating hour after completion of the tests, the appropriate default NO_x emission rate(s) obtained from the fuel-and-unit-specific testing shall be used for emissions reporting.

(b) On-going qualification and disqualification.

- (1) Once a low mass emissions unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit no more than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section. The calculation methodology used for the annual demonstration shall be the methodology described in the certification application under paragraph (a)(2)(iii) of this section.
- (2) If any low mass emissions unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative emissions for the unit exceed the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section at the end of any calendar year or ozone season, then:

- (i) The low mass emissions unit shall be disqualified from using the low mass emissions excepted methodology; and
 - (ii) The owner or operator of the low mass emissions unit shall install and certify monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13, and shall report SO₂ (Acid Rain Program units, only), NO_x, and CO₂ (Acid Rain Program units, only) emissions data and heat input data from such monitoring systems by December 31 of the calendar year following the year in which the unit exceeded the number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section; and
 - (iii) If the required monitoring systems have not been installed and certified by the applicable deadline in paragraph (b)(2)(ii) of this section, the owner or operator shall report the following values for each unit operating hour, beginning with the first operating hour after the deadline and continuing until the monitoring systems have been provisionally certified: the maximum potential hourly heat input for the unit, as defined in § 72.2 of this chapter; the SO₂ emissions, in lb/hr, calculated using the applicable default SO₂ emission rate from paragraph (c)(1)(i) of this section and the maximum potential hourly unit heat input; the CO₂ emissions, in tons/hr, calculated using the applicable default CO₂ emission rate from paragraph (c)(1)(iii) of this section and the maximum potential hourly unit heat input; and the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter.
- (3) If a low mass emissions unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install and certify SO₂ (Acid Rain Program units, only), NO_x, and CO₂ (Acid Rain Program units, only) and flow (if necessary) monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel, and shall report emissions data from such monitoring systems beginning with the date and hour on which the new fuel is first combusted in the unit. If the required monitoring systems are not installed and certified prior to the fuel switch, the owner or operator shall report (as applicable) the maximum potential concentration of SO₂, CO₂ and NO_x, the maximum potential NO_x emission rate, the maximum potential flowrate, the maximum potential hourly heat input and the maximum (or minimum, if appropriate) potential moisture percentage, from the date and hour of the fuel switch until the monitoring systems are certified or until probationary calibration error tests of the monitors are passed and the conditional data validation procedures in § 75.20(b)(3) begin to be used. All maximum and minimum potential values shall be specific to the new fuel and shall be determined in a manner consistent with section 2 of appendix A to this part and § 72.2 of this chapter. The owner or operator must notify the Administrator (or the permitting authority) in the case where a unit switches fuels without previously having installed and certified a SO₂, NO_x and CO₂ monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.
- (4) If a new or newly-affected unit initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use the low mass emissions methodology for the unit, he or she must:

- (i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a new unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a new unit subject to a NO_x mass reduction program under subpart H of this part. For newly-affected units, the records in paragraph (c)(2) of this section shall be kept as follows:
 - (A) For Acid Rain Program units, begin keeping the records as of the first hour of commercial operation of the unit following the date on which the unit becomes affected; or
 - (B) For units subject to a NO_x mass reduction program under subpart H of this part, begin keeping the records as of the first hour of unit operation following the date on which the unit becomes an affected unit;
- (ii) Use these records to determine the cumulative heat input and SO₂, CO₂, and/or NO_x mass emissions in order to continue to qualify as a low mass emissions unit; and
- (iii) Determine the cumulative SO₂ and/or NO_x mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in Tables LM-1, LM-2, and LM-3 of this section or use the fuel-and-unit-specific NO_x emission rate determined according to paragraph (c)(1)(iv) of this section. For Acid Rain Program LME units, the Administrator will not count SO₂ mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under § 75.4 against SO₂ allowances to be held in the unit account.

- (5) A low mass emissions unit that has been disqualified from using the low mass emissions excepted methodology may subsequently submit an application to qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section only if, following the non-compliant year (or ozone season), at least three full years (or ozone seasons) of actual, monitored emissions data is obtained showing that the unit emitted no more than the applicable number of tons of SO₂ and/or NO_x specified in paragraph (a)(1)(i)(A) of this section. Further, the designated representative or authorized account representative must certify in the application that the unit operation for the years or ozone seasons for which the emissions were monitored are representative of the projected future operation of the unit.

(c) *Low mass emissions excepted methodology, calculations, and values –*

(1) *Determination of SO₂, NO_x, and CO₂ emission rates.*

- (i) If the unit combusts only natural gas and/or fuel oil, use Table LM-1 of this section to determine the appropriate SO₂ emission rate for use in calculating hourly SO₂ mass emissions under this section. Alternatively, for fuel oil combustion, a lower, fuel-specific SO₂ emission factor may be used in lieu of the applicable emission factor from Table LM-1, if a federally enforceable permit condition is in place that limits the sulfur content of the oil. If this alternative is chosen, the fuel-specific SO₂ emission rate in lb/mmBtu shall be calculated by multiplying the fuel sulfur content limit (weight percent sulfur) by 1.01. In addition, the owner or operator shall periodically determine the sulfur content of the oil combusted in the unit, using one of the oil sampling and analysis options described in section 2.2 of appendix D to this part, and shall keep records of these fuel sampling results in a format suitable for inspection and auditing. Alternatively, the required oil sampling and associated recordkeeping may be performed using a consensus standard (e.g., ASTM, API, etc.) that is prescribed in the unit's Federally-enforceable operating

permit, in an applicable State regulation, or in another applicable Federal regulation. If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO₂ emission rate for each such fuel.

- (ii) If the unit combusts only natural gas and/or fuel oil, use either the appropriate NO_x emission factor from Table LM-2 of this section, or a fuel-and-unit-specific NO_x emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_x mass emissions under this section. If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific NO_x emission rate according to paragraph (c)(1)(iv) of this section.
- (iii) If the unit combusts only natural gas and/or fuel oil, use Table LM-3 of this section to determine the appropriate CO₂ emission rate for use in calculating hourly CO₂ mass emissions under this section (Acid Rain Program units, only). If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific CO₂ emission rate for the fuel, as follows:
 - (A) Derive a carbon-based F-factor for the fuel, using fuel sampling and analysis, as described in section 3.3.6 of appendix F to this part; and
 - (B) Use Equation G-4 in appendix G to this part to derive the default CO₂ emission rate. Rearrange the equation, solving it for the ratio of W_{CO₂}/H (this ratio will yield an emission rate, in units of tons/mmBtu). Then, substitute the carbon-based F-factor determined in paragraph (c)(1)(iii)(A) of this section into the rearranged equation to determine the default CO₂ emission rate for the unit.
- (iv) In lieu of using the default NO_x emission rate from Table LM-2 of this section, the owner or operator may, for each fuel combusted by a low mass emissions unit, determine a fuel-and-unit-specific NO_x emission rate for the purpose of calculating NO_x mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. The testing must be completed in a timely manner, such that the test results are reported electronically no later than the end of the calendar year or ozone season in which the LME methodology is first used. If this option is chosen, the following procedures shall be used.
 - (A) Except as otherwise provided in paragraphs (c)(1)(iv)(F), (c)(1)(iv)(G), and (c)(1)(iv)(I) of this section, determine a fuel-and-unit-specific NO_x emission rate by conducting a four load NO_x emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:
 - (1) Do not measure the heat input as required under 2.1.3 of appendix E to this part.
 - (2) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

- (3) Do not correct the NO_x concentration to 15% O₂.
- (4) If the testing is performed on an uncontrolled diffusion flame turbine, a correction to the observed average NO_x concentration from each run of the test must be applied using the following Equation LM-1a.

$$NO_{x_{corr}} = NO_{x_{obs}} \left(\frac{P_r}{P_o} \right)^{0.5} e^{19(H_r - H_o)} \left(\frac{T_r}{T_o} \right)^{1.3} \quad (\text{Eq. LM-1a})$$

Where:

NO_{x_{corr}} = Corrected NO_x concentration (ppm).

NO_{x_{obs}} = Average measured NO_x concentration for each run of the test (ppm).

P_r = Average annual atmospheric pressure (or average ozone season atmospheric pressure for a Subpart H unit that reports data only during the ozone season) at the nearest weather station (e.g., a standardized NOAA weather station located at the airport) for the year (or ozone season) prior to the year of the test (mm Hg).

P_o = Observed atmospheric pressure during the test run (mm Hg).

H_r = Average annual atmospheric humidity ratio (or average ozone season humidity ratio for a Subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (g H₂O/g air).

H_o = Observed humidity ratio during the test run (g H₂O/g air).

T_r = Average annual atmospheric temperature (or average ozone season atmospheric temperature for a Subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (° K).

T_a = Observed atmospheric temperature during the test run (° K).

- (B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.
 - (1) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.
 - (2) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table LM-4 of this section.

- (3) [Reserved]
 - (4) If the acceptance criteria in paragraph (c)(1)(iv)(B)(1) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.
 - (5) Fuel and unit specific NO_x emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.
- (C) Based on the results of the part 75 appendix E testing, determine the fuel-and-unit-specific NO_x emission rate as follows:
- (1) Except for LME units that use selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to control NO_x emissions, the highest three-run average NO_x emission rate obtained at any load in the appendix E test for a particular type of fuel shall be the fuel-and-unit-specific NO_x emission rate, for that type of fuel.
 - (2) [Reserved]
 - (3) For a group of identical low mass emissions units (except for units that use SCR or SNCR to control NO_x emissions), the fuel-and-unit-specific NO_x emission rate for all units in the group, for a particular type of fuel, shall be the highest three-run average NO_x emission rate obtained at any tested load from any unit tested in the group, for that type of fuel.
 - (4) Except as provided in paragraphs (c)(1)(iv)(C)(7) and (c)(1)(iv)(C)(8) of this section, for an individual low mass emissions unit which uses SCR or SNCR to control NO_x emissions, the fuel-and-unit-specific NO_x emission rate for each type of fuel combusted in the unit shall be the higher of:
 - (i) The highest three-run average emission rate from any load of the appendix E test for that type of fuel; or
 - (ii) 0.15 lb/mmBtu.
 - (5) [Reserved]
 - (6) Except as provided in paragraphs (c)(1)(iv)(C)(7) and (c)(1)(iv)(C)(8) of this section, for a group of identical low mass emissions units that are all equipped with SCR or SNCR to control NO_x emissions, the fuel-and-unit-specific NO_x emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:
 - (i) The highest three-run average NO_x emission rate at any load from all appendix E tests of all tested units in the group, for that type of fuel; or
 - (ii) 0.15 lb/mmBtu.
 - (7) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(4) and (c)(1)(iv)(C)(6) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) and water (or steam) injection to control NO_x emissions:
 - (i) If the appendix E testing is performed when the water (or steam) injection is in use and either upstream of the SCR or SNCR or during a time period when the SCR or SNCR is out of service; then

- (ii) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_x emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the water-to-fuel ratio is within the acceptable range established during the appendix E testing.
 - (8) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(4) and (c)(1)(iv)(C)(6) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) and uses dry low-NO_x technology to control NO_x emissions:
 - (i) If the appendix E testing is performed during a time period when the dry low-NO_x controls are in use, but the SCR or SNCR is out of service; then
 - (ii) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_x emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the parametric data described in paragraph (c)(1)(iv)(H)(2) of this section demonstrate that the dry low-NO_x controls are operating in the premixed or low-NO_x mode.
 - (9) For an individual combustion turbine (or a group of identical turbines) that operate principally at base load (or at a set point temperature), but are capable of operating at a higher peak load (or higher internal operating temperature), the fuel-and-unit-specific NO_x emission rate for the unit (or for each unit in the group) shall be as follows:
 - (i) If the testing is done only at base load, use the three-run average NO_x emission rate for base load operating hours and 1.15 times that emission rate for peak load operating hours; or
 - (ii) If the testing is done at both base load and peak load, use the three-run average NO_x emission rate from the base load testing for base load operating hours and the three-run average NO_x emission rate from the peak load testing for peak load operating hours.
- (D) For each low mass emissions unit, or group of identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_x emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_x emission rate every five years (20 calendar quarters), unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_x emission rate. If such changes occur, the fuel-and-unit-specific NO_x emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. Testing shall be done at the number of loads specified in paragraph (c)(1)(iv)(A) or (c)(1)(iv)(I) of this section, as applicable. If a low mass emissions unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_x emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_x emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_x emission rate unless such unit also undergoes

changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_x emission rates.

- (E) Each low mass emissions unit or each low mass emissions unit in a group of identical units for which a fuel-and-unit-specific NO_x emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.
- (F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_x emission rate(s). However, fuel-and-unit-specific NO_x emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.
- (G) Low mass emissions units for which at least 3 years of quality-assured NO_x emission rate data from a NO_x-diluent CEMS that meets the quality assurance requirements of either: this part, or appendix F to part 60 of this chapter, or a comparable State CEM program, and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_x emission rates from the actual data using the following procedure. Separate the actual NO_x emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_x emission rate. Determine the 95th percentile NO_x emission rate for each data set as defined in § 72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_x emission rate, except that for a unit that uses SCR or SNCR for NO_x emission control, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_x emission rate.
- (H) For low mass emission units with add-on NO_x emission controls, and for units that use dry low-NO_x technology, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_x emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_x controls are operating properly and to allow the determination of the correct NO_x emission rate as required under paragraph (c)(1)(iv) of this section.
 - (1) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_x emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_x controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_x emission rate may not be used for that hour, and the appropriate default NO_x emission rate from Table LM-2 shall be reported instead.

- (2) For a low mass emissions unit that uses dry low-NO_x premix technology to control NO_x emissions, proper operation of the emission controls means that the unit is in the low-NO_x or premixed combustion mode, and fired with natural gas. Evidence of operation in the low-NO_x or premixed mode shall be provided by monitoring the appropriate turbine operating parameters. These parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane (IGV) position, and flame detection or flame scanner condition. The acceptable values and ranges for all parameters monitored shall be specified in the monitoring plan for the unit, and the parameters shall be monitored during each subsequent operating hour. If one or more of these parameters is not within the acceptable range or at an acceptable value in a given operating hour, the fuel-and-unit-specific NO_x emission rate may not be used for that hour, and the appropriate default NO_x emission rate from Table LM-2 shall be reported instead. When the unit is fired with oil the appropriate default value from Table LM-2 shall be reported.
 - (3) For low mass emission units with other types of add-on NO_x controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_x controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_x emission rates may not be used in that hour, and the appropriate default NO_x emission rate from Table LM-2 shall be reported instead.
- (I) Notwithstanding the requirements in paragraph (c)(1)(iv)(A) of this section, the appendix E testing to determine (or re-determine) the fuel-specific, unit-specific NO_x emission rate for a unit (or for each unit in a group of identical units) may be performed at fewer than four loads, under the following circumstances:
- (1) Testing may be done at one load level if the data analysis described in paragraph (c)(1)(iv)(J) of this section is performed and the results show that the unit has operated (or all units in the group of identical units have operated) at a single load level for at least 85.0 percent of all operating hours in the previous three years (12 calendar quarters) prior to the calendar quarter of the appendix E testing. For combustion turbines that are operated to produce approximately constant output (in MW) but which use internal operating and exhaust temperatures and not the actual output in MW to control the operation of the turbine, the internal operating temperature set point may be used as a surrogate for load in demonstrating that the unit qualifies for single-load testing. If the data analysis shows that the unit does not qualify for single-load testing, testing may be done at two (or three) load levels if the unit has operated (or if all units in the group of identical units have operated) cumulatively at two (or three) load levels for at least 85.0 percent of all operating hours in the previous three years; or
 - (2) If a multiple-load appendix E test was initially performed for a unit (or group of identical units) to determine the fuel-and-unit specific NO_x emission rate, then the periodic retests required under paragraph (c)(1)(iv)(D) of this section may be single-load tests, performed at the load level for which the highest average NO_x emission rate was obtained in the initial test.

- (3) The initial appendix E testing may be performed at a single load, between 75 and 100 percent of the maximum sustainable load defined in the monitoring plan for the unit, if the average annual capacity factor of the LME unit, when calculated according to the definition of "capacity factor" in § 72.2 of this chapter, is 2.5 percent or less for the three calendar years immediately preceding the year of the testing, and that the annual capacity factor does not exceed 4.0 percent in any of those three years. Similarly, for a LME unit that reports emissions data on an ozone season-only basis, the initial appendix E testing may be performed at a single load between 75 and 100 percent of the maximum sustainable load if the 2.5 and 4.0 percent capacity factor requirements are met for the three ozone seasons immediately preceding the date of the emission testing (see § 75.74(c)(11)). For a group of identical LME units, any unit(s) in the group that meet the 2.5 and 4.0 percent capacity factor requirements may perform the initial appendix E testing at a single load between 75 and 100 percent of the maximum sustainable load.
- (4) The retest of any LME unit may be performed at a single load between 75 and 100 percent of the maximum sustainable load if, for the three calendar years immediately preceding the year of the retest (or, if applicable, the three ozone seasons immediately preceding the date of the retest), the applicable capacity factor requirements described in paragraph (c)(1)(iv)(I)(3) of this section are met.
- (5) Alternatively, for combustion turbines, the single-load testing described in paragraphs (c)(1)(iv)(I)(3) and (c)(1)(iv)(I)(4) of this section may be performed at the highest attainable load level corresponding to the season of the year in which the testing is conducted.
- (6) In all cases where the alternative single-load testing option described in paragraphs (c)(1)(iv)(I)(3) through (c)(1)(iv)(I)(5) of this section is used, the owner or operator shall keep records documenting that the required capacity factor requirements were met.
- (J) To determine whether a unit qualifies for testing at fewer than four loads under paragraph (c)(1)(iv)(I) of this section, follow the procedures in paragraph (c)(1)(iv)(J)(1) or (c)(1)(iv)(J)(2) of this section, as applicable.
 - (1) Determine the range of operation of the unit, according to section 6.5.2.1 of appendix A to this part. Divide the range of operation into four equal load bands. For example, if the range of operation extends from 20 MW to 100 MW, the four equal load bands would be: band #1: from 20 MW to 40 MW; band #2: from 41 MW to 60 MW; band #3: from 61 MW to 80 MW; and band #4: from 81 to 100 MW. Then, perform a historical load analysis for all unit operating hours in the 12 calendar quarters preceding the quarter of the test. Alternatively, for sources that report emissions data only during the ozone season, the historical load analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. Determine the percentage of the data that fall into each load band. For a unit that is not part of a group of identical units, if 85.0% or more of the data fall into one load band, single-load testing may be performed at any point within that load band. For a group of identical units, if each unit in the group meets the 85.0% criterion, then representative single-load testing within the load band may be

performed. If the 85.0% criterion cannot be met to qualify for single-load testing but this criterion can be met cumulatively for two (or three) load levels, then testing may be performed at two (or three) loads instead of four.

- (2) For a combustion turbine that uses exhaust temperature and not the actual output in megawatts to control the operation of the turbine (or for a group of identical units of this type), the owner or operator must document that the unit (or each unit in the group) has operated within $\pm 10\%$ of the set point temperature for 85.0% of the operating hours in the previous 12 calendar quarters to qualify for single-load testing. Alternatively, for sources that report emissions data only during the ozone season, the historical set point temperature analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. When the set point temperature is used rather than unit load to justify single-load testing, the designated representative shall certify in the monitoring plan for the unit that this is the normal manner of unit operation and shall document the setpoint temperature.
- (2) **Records of operating time, fuel usage, unit output and NO_x emission control operating status.** The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection, except that for unmanned facilities, the records may be kept at a central location, rather than on-site:
 - (i) For each low mass emissions unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.
 - (ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type(s) of fuel(s) combusted in the unit during each hour of unit operation.
 - (iii) For each low mass emissions unit using the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit load (in megawatts or thousands of pounds of steam per hour), for the purpose of apportioning heat input to the individual unit operating hours.
 - (iv) For each low mass emissions unit with add-on NO_x emission controls of any kind and each unit that uses dry low-NO_x technology, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_x controls.
- (3) **Heat input.** Hourly, quarterly and annual heat input for a low mass emissions unit shall be determined using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.
 - (i) **Maximum rated hourly heat input method.**
 - (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, H_{hr} , the hourly heat input (mmBtu) to a low mass emissions unit shall be deemed to equal the maximum rated hourly heat input, as defined in § 72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator

may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

- (B) The quarterly heat input, HI_{qtr} , in mmBtu, shall be determined using Equation LM-1:

$$HI_{qtr} = \sum_{i=1}^n HI_{hr} \quad (\text{Eq. LM-1})$$

Where:

n = Number of unit operating hours in the quarter.

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

- (C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.
- (D) For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall, for compliance purposes, include only the heat input for the months of May and June, and the cumulative ozone season heat input shall be the sum of the heat input values for May, June and the third calendar quarter of the year.
- (ii) **Long term fuel flow heat input method.** The owner or operator may, for the purpose of demonstrating that a low mass emissions unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emissions unit.
- (A) This option may be used for a group of low mass emission units only if:
- (1) The low mass emission units combust fuel from a common source of supply; and
 - (2) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and
 - (3) All of the units in the group are low mass emission units.
- (B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;
- (1) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

- (2) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3-Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2-Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, March 2001); Section 4-Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, September 2000); and Section 5-Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (all incorporated by reference under § 75.6 of this part); or
 - (3) A fuel flow meter certified and maintained according to appendix D to this part.
- (C) Except as provided in paragraph (c)(3)(ii)(C)(3) of this section, for each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:
- (1) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest GCV from the samples taken in the current year); or
 - (2) Using the appropriate default gross calorific value listed in Table LM-5 of this section.
 - (3) For gaseous fuels other than pipeline natural gas or natural gas, the GCV sampling frequency shall be daily unless the results of a demonstration under section 2.3.5 of appendix D to this part show that the fuel has a low GCV variability and qualifies for monthly sampling. If daily GCV sampling is required, use the highest GCV obtained in the calendar quarter as GCV_{max} in Equation LM-3, of this section.
- (D) If Eq. LM-2 is used for heat input determination, the specific gravity of each type of fuel oil combusted during the quarter shall be determined either by:
- (1) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest specific gravity from the samples taken in the current year); or
 - (2) Using the appropriate default specific gravity value in Table LM-6 of this section.
- (E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emissions unit or group of low mass emissions units sharing a common fuel supply shall be determined using either Equation LM-2 or Equation LM-3 for oil (as applicable to the method used to quantify oil usage) and Equation LM-3 for gaseous fuels. For a unit subject to the provisions of subpart H of this part, which is not required to report emission

data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall include only the heat input for the months of May and June.

$$HI_{fuel-qtr} = M_{qtr} \frac{GCV_{max}}{10^6} \quad \text{Eq. LM-2 (for fuel oil)}$$

Where:

$HI_{fuel-qtr}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb).

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel-qtr} = Q_{qtr} \frac{GCV_{max}}{10^6} \quad \text{Eq. LM-3 (for gaseous fuel or fuel oil)}$$

Where:

$HI_{fuel-qtr}$ = Quarterly heat input from gaseous fuel or fuel oil (mmBtu).

Q_{qtr} = Volume of gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf) or (gal), as applicable.

GCV_{max} = Gross calorific value of the gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf) or (Btu/gal), as applicable.

10^6 = Conversion of Btu to mmBtu.

- (F) Use Eq. LM-4 to calculate $HI_{qtr-total}$, the quarterly heat input (mmBtu) for all fuels. $HI_{qtr-total}$ shall be the sum of the $HI_{fuel-qtr}$ values determined using Equations LM-2 and LM-3.

$$HI_{qtr-total} = \sum_{all\ fuel} HI_{fuel-qtr} \quad \text{(Eq. LM-4)}$$

- (G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input ($HI_{qtr-total}$) values for all calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the cumulative ozone season heat input shall be the sum of the quarterly heat input values for the second and third calendar quarters of the year.

- (H) For each low mass emissions unit or each low mass emissions unit in a group of identical units, the owner or operator shall determine the cumulative quarterly unit load in megawatt hours or thousands of pounds of steam. The quarterly cumulative unit load shall be the sum of the hourly unit load values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM-5 or LM-6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

$$MW_{qtr} = \sum_{all\text{-}hours} MW \quad \text{Eq. LM-5 (for MW output)}$$

$$ST_{qtr} = \sum_{all\text{-}hours} ST \quad \text{Eq. LM-6 (for steam output)}$$

Where:

MW_{qtr} = Sum of all unit operating loads recorded during the quarter by the unit (MWh).

$ST_{fuel\text{-}qtr}$ = Sum of all hourly steam loads recorded during the quarter by the unit (klb of steam/hr).

MW = Unit operating load for a particular unit operating hour (MWh).

ST = Unit steam load for a particular unit operating hour (klb of steam).

- (I) For a low mass emissions unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr\text{-}total}$ to each hour of unit operation using either Equation LM-7 or LM-8:

$$HI_{hr} = HI_{qtr\text{-}total} \frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM-7 for MW output)

$$HI_{hr} = HI_{qtr\text{-}total} \frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM-8 for steam output)

Where:

HI_{hr} = Hourly heat input to the unit (mmBtu).

MW_{hr} = Hourly operating load for the unit (MW).

ST_{hr} = Hourly steam load for the unit (klb of steam/hr).

- (J) For each low mass emissions unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of operation using either Equation LM-7a or LM-8a:

$$HI_{hr} = HI_{qtr-total} \frac{MW_{hr}}{\sum_{all-units} MW_{qtr}}$$

(Eq LM-7a for MW output)

$$HI_{hr} = HI_{qtr-total} \frac{ST_{hr}}{\sum_{all-units} ST_{qtr}}$$

(Eq LM-8a for steam output)

Where:

HI_{hr} = Hourly heat input to the individual unit (mmBtu).

MW_{hr} = Hourly operating load for the individual unit (MW).

ST_{hr} = Hourly steam load for the individual unit (klb of steam/hr).

ΣMW^{qtr} = Sum of the quarterly operating

all-units loads (from Eq. LM-5) for all units in the group (MW).

ΣST^{qtr} = Sum of the quarterly steam

all-units loads (from Eq. LM-6) for all units in the group (klb of steam/hr)

- (4) **Calculation of SO_2 , NO_x and CO_2 mass emissions.** The owner or operator shall, for the purpose of demonstrating that a low mass emissions unit meets the requirements of this section, calculate SO_2 , NO_x and CO_2 mass emissions in accordance with the following.

- (i) **SO_2 mass emissions.**

- (A) The hourly SO_2 mass emissions (lbs) for a low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM-9 and the appropriate fuel-based SO_2 emission factor for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$W_{SO_2} = EF_{SO_2} \times HI_{hr} \text{ (Eq. LM-9)}$$

Where:

W_{SO_2} = Hourly SO_2 mass emissions (lbs.)

EF_{SO_2} = Either the SO_2 emission factor from Table LM-1 of this section or the fuel-and-unit-specific SO_2 emission rate from paragraph (c)(1)(i) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

- (B) The quarterly SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.
- (C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii)

- (A) The hourly NO_x mass emissions for the low mass emissions unit (lbs) shall be determined using Equation LM-10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_x emission controls of any kind and for which a fuel-and-unit-specific NO_x emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_x emission controls are operating properly, use the NO_x emission rate from Table LM-2 of this section for the fuel combusted during the hour with the highest NO_x emission rate.

$$W_{NOX} = EF_{NOX} \times HI_{hr} \text{ (Eq. LM-10)}$$

Where:

W_{NOX} = Hourly NO_x mass emissions (lbs).

EF_{NOX} = Either the NO_x emission factor from Table LM-2 of this section or the fuel- and unit-specific NO_x emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

- (B) The quarterly NO_x mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly NO_x mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.
- (C) The year-to-date cumulative NO_x mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly NO_x mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the ozone season NO_x mass emissions for the unit shall be the sum of the quarterly NO_x mass

emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for the second and third calendar quarters of the year, and the second quarter report shall include emissions data only for May and June.

- (D) The quarterly and cumulative NO_x emission rate in lb/mmBtu (if required by the applicable program(s)) shall be determined as follows. Calculate the quarterly NO_x emission rate by taking the arithmetic average of all of the hourly EF_{NO_x} values. Calculate the cumulative (year-to-date) NO_x emission rate by taking the arithmetic average of the quarterly NO_x emission rates.

(iii) **CO₂ Mass Emissions.**

- (A) The hourly CO₂ mass emissions (tons) for the affected low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM-11 and the appropriate fuel-based CO₂ emission factor from Table LM-3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$WCO_2 = EFCO_2 \times HI_{hr} \text{ (Eq. LM-11)}$$

Where:

WCO₂ = Hourly CO₂ mass emissions (tons).

EF_{CO₂} = Either the fuel-based CO₂ emission factor from Table LM-3 of this section or the fuel-and-unit-specific CO₂ emission rate from paragraph (c)(1)(iii) of this section (tons/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

- (B) The quarterly CO₂ mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly CO₂ mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A) of this section.
- (C) The year-to-date cumulative CO₂ mass emissions (tons) for the low mass emissions unit shall be the sum of all of the quarterly CO₂ mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.
- (d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.
- (e) The quality control and quality assurance requirements in § 75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

- (1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for long term fuel flow determinations.
- (2) For low mass emissions units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use one of the methods specified in paragraph (c)(3)(ii)(B)(2) of this section to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.
- (3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.
- (4) For each low mass emissions unit for which fuel-and-unit-specific NO_x emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_x emission rate tests conducted according to appendix E to this part. If CEMS data are used to determine the fuel-and-unit-specific NO_x emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_x emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_x emission rates are re-determined.
- (5) For each low mass emissions unit for which fuel-and-unit-specific NO_x emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which has add-on NO_x emission controls of any kind or uses dry low-NO_x technology, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_x controls.
- (6) For unmanned facilities, the records required by paragraphs (e)(1), (e)(2) and (e)(4) of this section may be kept at a central location, rather than at the facility.

TABLE LM-1—SO₂ EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES

Fuel type	SO ₂ emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.

Fuel type	SO ₂ emission factors
Diesel Fuel	0.5 lb/mmBtu.

TABLE LM-2—NO_x EMISSION RATES (LB/MMBTU) FOR VARIOUS BOILER/FUEL TYPES

Unit type	Fuel type	NO _x emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

TABLE LM-3—CO₂ EMISSION FACTORS (TON/MMBTU) FOR GAS AND OIL

Fuel type	CO ₂ emission factors
Pipeline (or other) Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

TABLE LM-4—IDENTICAL UNIT TESTING REQUIREMENTS

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2
7	3
>7	n tests; where n = number of units divided by 3 and rounded to

Number of identical units in the group	Number of appendix E tests required
	nearest integer.

TABLE LM-5—DEFAULT GROSS CALORIFIC VALUES (GCVs) FOR VARIOUS FUELS

Fuel	GCV for use in equation LM-2 or LM-3
Pipeline Natural Gas	1050 Btu/scf.
Other Natural Gas	1100 Btu/scf.
Residual Oil	19,700 Btu/lb or 167,500 Btu/gallon.
Diesel Fuel	20,500 Btu/lb or 151,700 Btu/gallon.

TABLE LM-6—DEFAULT SPECIFIC GRAVITY VALUES FOR FUEL OIL

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

[63 FR 57500, Oct. 27, 1998, as amended at 64 FR 28592, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40424, 40425, June 12, 2002; 67 FR 53504, Aug. 16, 2002; 73 FR 4344, Jan. 24, 2008]

Subpart C—Operation and Maintenance Requirements

§ 75.20 Initial certification and recertification procedures.

(a) **Initial certification approval process.** The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part meets the initial certification requirements of this section and shall ensure that all applicable initial certification tests under paragraph (c) of this section are completed by the deadlines specified in § 75.4 and prior to use in the Acid Rain Program. In addition, whenever the owner or operator installs a continuous emission or opacity monitoring system in order to meet the requirements of §§ 75.11 through 75.18, where no continuous emission or opacity monitoring system was previously installed, initial certification is required.

(1) **Notification of initial certification test dates.** The owner or operator or designated representative shall submit a written notice of the dates of initial certification testing at the unit as specified in § 75.61(a)(1).

- (2) **Certification application.** The owner or operator shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The owner or operator shall submit the certification application in accordance with § 75.60 and each complete certification application shall include the information specified in § 75.63.
- (3) **Provisional approval of certification (or recertification) applications.** Upon the successful completion of the required certification (or recertification) procedures of this section, each continuous emission or opacity monitoring system shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification (or recertification) application under paragraph (a)(4) of this section. Notwithstanding this paragraph, no continuous emission or opacity monitor systems for a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program. Data measured and recorded by a provisionally certified (or recertified) continuous emission or opacity monitoring system, operated in accordance with the requirements of appendix B to this part, will be considered valid quality-assured data (retroactive to the date and time of provisional certification or recertification), provided that the Administrator does not invalidate the provisional certification (or recertification) by issuing a notice of disapproval within 120 days of receipt by the Administrator of the complete certification (or recertification) application. Note that when the conditional data validation procedures of paragraph (b)(3) of this section are used for the initial certification (or recertification) of a continuous emissions monitoring system, the date and time of provisional certification (or recertification) of the CEMS may be earlier than the date and time of completion of the required certification (or recertification) tests.
- (4) **Certification (or recertification) application formal approval process.** The Administrator will issue a notice of approval or disapproval of the certification (or recertification) application to the owner or operator within 120 days of receipt of the complete certification (or recertification) application. In the event the Administrator does not issue such a notice within 120 days of receipt, each continuous emission or opacity monitoring system which meets the performance requirements of this part and is included in the certification (or recertification) application will be deemed certified (or recertified) for use under the Acid Rain Program.
- (i) **Approval notice.** If the certification (or recertification) application is complete and shows that each continuous emission or opacity monitoring system meets the performance requirements of this part, then the Administrator will issue a notice of approval of the certification (or recertification) application within 120 days of receipt.
- (ii) **Incomplete application notice.** A certification (or recertification) application will be considered complete when all of the applicable information required to be submitted in § 75.63 has been received by the Administrator, the EPA Regional Office, and the appropriate State and/or local air pollution control agency. If the certification (or recertification) application is not complete, then the Administrator will issue a notice of incompleteness that provides a reasonable timeframe for the designated representative to submit the additional information required to complete the certification (or recertification) application. If the designated representative has not complied with the notice of incompleteness by a specified due date, then the Administrator may issue a notice of disapproval specified under paragraph (a)(4)(iii) of this section. The 120-day review period shall not begin prior to receipt of a complete application.

- (iii) **Disapproval notice.** If the certification (or recertification) application shows that any continuous emission or opacity monitoring system does not meet the performance requirements of this part, or if the certification (or recertification) application is incomplete and the requirement for disapproval under paragraph (a)(4)(ii) of this section has been met, the Administrator shall issue a written notice of disapproval of the certification (or recertification) application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification (or recertification) is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system shall not be considered valid quality-assured data as follows: from the hour of the probationary calibration error test that began the initial certification (or recertification) test period (if the conditional data validation procedures of paragraph (b)(3) of this section were used to retrospectively validate data); or from the date and time of completion of the invalid certification or recertification tests (if the conditional data validation procedures of paragraph (b)(3) of this section were not used). The owner or operator shall follow the procedures for loss of initial certification in paragraph (a)(5) of this section for each continuous emission or opacity monitoring system which is disapproved for initial certification. For each disapproved recertification, the owner or operator shall follow the procedures of paragraph (b)(5) of this section.
- (iv) **Audit decertification.** The Administrator may issue a notice of disapproval of the certification status of a continuous emission or opacity monitoring system, in accordance with § 75.21.
- (5) **Procedures for loss of certification.** When the Administrator issues a notice of disapproval of a certification application or a notice of disapproval of certification status (as specified in paragraph (a)(4) of this section), then:
 - (i) Until such time, date, and hour as the continuous emission monitoring system can be adjusted, repaired, or replaced and certification tests successfully completed (or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section are used, until a probationary calibration error test is passed following corrective actions in accordance with paragraph (b)(3)(ii) of this section), the owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in § 75.21: the maximum potential concentration of SO₂, as defined in section 2.1.1.1 of appendix A to this part, to report SO₂ concentration; the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, to report NO_x emissions in lb/mmBtu; the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, to report NO_x emissions in ppm (when a NO_x concentration monitoring system is used to determine NO_x mass emissions, as defined under § 75.71(a)(2)); the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, to report volumetric flow; the maximum potential concentration of CO₂, as defined in section 2.1.3.1 of appendix A to this part, to report CO₂ concentration data; and either the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part or, if Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, the maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part; and
 - (ii) The designated representative shall submit a notification of certification retest dates as specified in § 75.61(a)(1)(ii) and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall repeat all certification tests or other requirements that were failed by the continuous emission or opacity monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(b) **Recertification approval process.** Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emission monitoring system or continuous opacity monitoring system that may significantly affect the ability of the system to accurately measure or record the SO₂ or CO₂ concentration, stack gas volumetric flow rate, NO_x emission rate, NO_x concentration, percent moisture, or opacity, or to meet the requirements of § 75.21 or appendix B to this part, the owner or operator shall recertify the continuous emission monitoring system or continuous opacity monitoring system, according to the procedures in this paragraph. 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 flow or concentration profile, the owner or operator shall recertify the monitoring system according to the procedures in this paragraph. Examples of changes which require recertification include: replacement of the analyzer; change in location or orientation of the sampling probe or site; and complete replacement of an existing continuous emission monitoring system or continuous opacity monitoring system. The owner or operator shall also recertify the continuous emission monitoring systems for a unit that has recommenced commercial operation following a period of long-term cold storage as defined in § 72.2 of this chapter. The owner or operator shall recertify a continuous opacity monitoring system whenever the monitor path length changes or as required by an applicable State or local regulation or permit. Any change to a flow monitor or gas monitoring system for which a RATA is not necessary shall not be considered a recertification event. In addition, changing the polynomial coefficients or K factor(s) of a flow monitor shall require a 3-load RATA, but is not considered to be a recertification event; however, records of the polynomial coefficients or K factor (s) currently in use shall be maintained on-site in a format suitable for inspection. Changing the coefficient or K factor(s) of a moisture monitoring system shall require a RATA, but is not considered to be a recertification event; however, records of the coefficient or K factor (s) currently in use by the moisture monitoring system shall be maintained on-site in a format suitable for inspection. In such cases, any other tests that are necessary to ensure continued proper operation of the monitoring system (e.g., 3-load flow RATAs following changes to flow monitor polynomial coefficients, linearity checks, calibration error tests, DAHS verifications, etc.) shall be performed as diagnostic tests, rather than as recertification tests. The data validation procedures in paragraph (b)(3) of this section shall be applied to RATAs associated with changes to flow or moisture monitor coefficients, and to linearity checks, 7-day calibration error tests, and cycle time tests, when these are required as diagnostic tests. When the data validation procedures of paragraph (b)(3) of this section are applied in this manner, replace the word "recertification" with the word "diagnostic."

(1) **Tests required.** For all recertification testing, the owner or operator shall complete all initial certification tests in paragraph (c) of this section that are applicable to the monitoring system, except as otherwise approved by the Administrator. For diagnostic testing after changing the flow rate monitor polynomial coefficients, the owner or operator shall complete a 3-level RATA. For diagnostic testing after changing the K factor or mathematical algorithm of a moisture monitoring system, the owner or operator shall complete a RATA.

(2) **Notification of recertification test dates.** The owner, operator, or designated representative shall submit notice of testing dates for recertification under this paragraph as specified in § 75.61(a)(1)(ii), unless all of the tests in paragraph (c) of this section are required for recertification, in which case the owner or operator shall provide notice in accordance with the notice provisions for initial certification testing in § 75.61(a)(1)(i).

- (3) **Recertification test period requirements and data validation.** The data validation provisions in paragraphs (b)(3)(i) through (b)(3)(ix) of this section shall apply to all CEMS recertifications and diagnostic testing. The provisions in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section may also be applied to initial certifications (see sections 6.2(a), 6.3.1(a), 6.3.2(a), 6.4(a) and 6.5(f) of appendix A to this part) and may be used to supplement the linearity check and RATA data validation procedures in sections 2.2.3(b) and 2.3.2(b) of appendix B to this part.
- (i) The owner or operator shall use substitute data, according to the standard missing data procedures in §§ 75.33 through 75.37 (or shall report emission data using a reference method or another monitoring system that has been certified or approved for use under this part), in the period extending from the hour of the replacement, modification or change made to a monitoring system that triggers the need to perform recertification testing, until either: the hour of successful completion of all of the required recertification tests; or the hour in which a probationary calibration error test (according to paragraph (b)(3)(ii) of this section) is performed and passed, following all necessary repairs, adjustments or reprogramming of the monitoring system. The first hour of quality-assured data for the recertified monitoring system shall either be the hour after all recertification tests have been completed or, if conditional data validation is used, the first quality-assured hour shall be determined in accordance with paragraphs (b)(3)(ii) through (b)(3)(ix) of this section. Notwithstanding these requirements, if the replacement, modification, or change requiring recertification of the CEMS is such that the historical data stream is no longer representative (e.g., where the SO₂ concentration and stack flow rate change significantly after installation of a wet scrubber), the owner or operator shall substitute for missing data as follows, in lieu of using the standard missing data procedures in §§ 75.33 through 75.37: for a change that results in a significantly higher concentration or flow rate, substitute maximum potential values according to the procedures in paragraph (a)(5) of this section; or for a change that results in a significantly lower concentration or flow rate, substitute data using the standard missing data procedures. The owner or operator shall then use the initial missing data procedures in § 75.31, beginning with the first hour of quality-assured data obtained with the recertified monitoring system, unless otherwise provided by § 75.34 for units with add-on emission controls.
- (ii) Once the modification or change to the CEMS has been completed and all of the associated repairs, component replacements, adjustments, linearization, and reprogramming of the CEMS have been completed, a probationary calibration error test is required to establish the beginning point of the recertification test period. In this instance, the first successful calibration error test of the monitoring system following completion of all necessary repairs, component replacements, adjustments, linearization and reprogramming shall be the probationary calibration error test. The probationary calibration error test must be passed before any of the required recertification tests are commenced.
- (iii) Beginning with the hour of commencement of a recertification test period, emission data recorded by the CEMS are considered to be conditionally valid, contingent upon the results of the subsequent recertification tests.
- (iv) Each required recertification test shall be completed no later than the following number of unit operating hours (or unit operating days) after the probationary calibration error test that initiates the test period:

- (A) For a linearity check and/or cycle time test, 168 consecutive unit operating hours, as defined in § 72.2 of this chapter or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter;
 - (B) For a RATA (whether normal-load or multiple-load), 720 consecutive unit operating hours, as defined in § 72.2 of this chapter or, for CEMS installed on common stacks or bypass stacks, 720 consecutive stack operating hours, as defined in § 72.2 of this chapter; and
 - (C) For a 7-day calibration error test, 21 consecutive unit operating days, as defined in § 72.2 of this chapter.
- (v) All recertification tests shall be performed hands-off. No adjustments to the calibration of the CEMS, other than the routine calibration adjustments following daily calibration error tests as described in section 2.1.3 of appendix B to this part, are permitted during the recertification test period. Routine daily calibration error tests shall be performed throughout the recertification test period, in accordance with section 2.1.1 of appendix B to this part. The additional calibration error test requirements in section 2.1.3 of appendix B to this part shall also apply during the recertification test period.
- (vi) If all of the required recertification tests and required daily calibration error tests are successfully completed in succession with no failures, and if each recertification test is completed within the time period specified in paragraph (b)(3)(iv)(A), (B), or (C) of this section, then all of the conditionally valid emission data recorded by the CEMS shall be considered quality-assured, from the hour of commencement of the recertification test period until the hour of completion of the required test(s).
- (vii) If a required recertification test is failed or aborted due to a problem with the CEMS, or if a daily calibration error test is failed during a recertification test period, data validation shall be done as follows:
- (A) If any required recertification test is failed, it shall be repeated. If any recertification test other than a 7-day calibration error test is failed or aborted due to a problem with the CEMS, the original recertification test period is ended, and a new recertification test period must be commenced with a probationary calibration error test. The tests that are required in the new recertification test period will include any tests that were required for the initial recertification event which were not successfully completed and any recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct the problems that caused the failure of the recertification test. For a 2- or 3-load flow RATA, if the relative accuracy test is passed at one or more load levels, but is failed at a subsequent load level, provided that the problem that caused the RATA failure is corrected without re-linearizing the instrument, the length of the new recertification test period shall be equal to the number of unit operating hours remaining in the original recertification test period, as of the hour of failure of the RATA. However, if re-linearization of the flow monitor is required after a flow RATA is failed at a particular load level, then a subsequent 3-load RATA is required, and the new recertification test period shall be 720 consecutive unit (or stack) operating hours. The new recertification test sequence shall not be commenced until all necessary maintenance activities, adjustments, linearizations, and reprogramming of the CEMS have been completed;

- (B) If a linearity check, RATA, or cycle time test is failed or aborted due to a problem with the CEMS, all conditionally valid emission data recorded by the CEMS are invalidated, from the hour of commencement of the recertification test period to the hour in which the test is failed or aborted, except for the case in which a multiple-load flow RATA is passed at one or more load levels, failed at a subsequent load level, and the problem that caused the RATA failure is corrected without re-linearizing the instrument. In that case, data invalidation shall be prospective, from the hour of failure of the RATA until the commencement of the new recertification test period. Data from the CEMS remain invalid until the hour in which a new recertification test period is commenced, following corrective action, and a probationary calibration error test is passed, at which time the conditionally valid status of emission data from the CEMS begins again;
- (C) If a 7-day calibration error test is failed within the recertification test period, previously-recorded conditionally valid emission data from the CEMS are not invalidated. The conditionally valid data status is unaffected, unless the calibration error on the day of the failed 7-day calibration error test exceeds twice the performance specification in section 3 of appendix A to this part, as described in paragraph (b)(3)(vii)(D) of this section; and
- (D) If a daily calibration error test is failed during a recertification test period (*i.e.*, the results of the test exceed twice the performance specification in section 3 of appendix A to this part), the CEMS is out-of-control as of the hour in which the calibration error test is failed. Emission data from the CEMS shall be invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test following corrective action, at which time the conditionally valid status of data from the monitoring system resumes. Failure to perform a required daily calibration error test during a recertification test period shall also cause data from the CEMS to be invalidated prospectively, from the hour in which the calibration error test was due until the hour of completion of a subsequent successful calibration error test. Whenever a calibration error test is failed or missed during a recertification test period, no further recertification tests shall be performed until the required subsequent calibration error test has been passed, re-establishing the conditionally valid status of data from the monitoring system. If a calibration error test failure occurs while a linearity check or RATA is still in progress, the linearity check or RATA must be re-started.
- (E) Trial gas injections and trial RATA runs are permissible during the recertification test period, prior to commencing a linearity check or RATA, for the purpose of optimizing the performance of the CEMS. The results of such gas injections and trial runs shall not affect the status of previously-recorded conditionally valid data or result in termination of the recertification test period, provided that the following specifications and conditions are met:
 - (1) For gas injections, the stable, ending monitor response is within ± 5 percent or within 5 ppm of the tag value of the reference gas;
 - (2) For RATA trial runs, the average reference method reading and the average CEMS reading for the run differ by no more than $\pm 10\%$ of the average reference method value or ± 15 ppm, or $\pm 1.5\%$ H₂O, or ± 0.02 lb/mmBtu from the average reference method value, as applicable;

- (3) No adjustments to the calibration of the CEMS are made following the trial injection(s) or run(s), other than the adjustments permitted under section 2.1.3 of appendix B to this part; and
 - (4) The CEMS is not repaired, re-linearized or reprogrammed (e.g., changing flow monitor polynomial coefficients, linearity constants, or K-factors) after the trial injection(s) or run(s).
- (F) If the results of any trial gas injection(s) or RATA run(s) are outside the limits in paragraphs (b)(3)(vii)(E)(1) or (2) of this section or if the CEMS is repaired, re-linearized or reprogrammed after the trial injection(s) or run(s), the trial injection(s) or run(s) shall be counted as a failed linearity check or RATA attempt. If this occurs, follow the procedures pertaining to failed and aborted recertification tests in paragraphs (b)(3)(vii)(A) and (b)(3)(vii)(B) of this section.
- (viii) If any required recertification test is not completed within its allotted time period, data validation shall be done as follows. For a late linearity test, RATA, or cycle time test that is passed on the first attempt, data from the monitoring system shall be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late 7-day calibration error test, whether or not it is passed on the first attempt, data from the monitoring system shall also be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late linearity test, RATA, or cycle time test that is failed on the first attempt or aborted on the first attempt due to a problem with the monitor, all conditionally valid data from the monitoring system shall be considered invalid back to the hour of the first probationary calibration error test which initiated the recertification test period. Data from the monitoring system shall remain invalid until the hour of successful completion of the late recertification test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct problems that caused failure of the late recertification test.
- (ix) If any required recertification test of a monitoring system has not been completed by the end of a calendar quarter and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report for that quarter. The owner or operator shall resubmit the report for that quarter if the required recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed recertification test. Alternatively, if any required recertification test is not completed by the end of a particular calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under § 75.64), the test data and results may be submitted with the earlier quarterly report even though the test date(s) are from the next calendar quarter. In such instances, if the recertification test(s) are passed in accordance with the provisions of paragraph (b)(3) of this section, conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the recertification test(s) is failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required. In addition, if the owner or operator uses a conditionally valid data flag in any of the four quarterly reports for a given year, the owner or operator shall indicate the final status of the conditionally valid data (i.e., resolved or unresolved) in the annual compliance certification report required under §

72.90 of this chapter for that year. The Administrator may invalidate any conditionally valid data that remains unresolved at the end of a particular calendar year and may require the owner or operator to resubmit one or more of the quarterly reports for that calendar year, replacing the unresolved conditionally valid data with substitute data values determined in accordance with § 75.31 or § 75.33, as appropriate.

- (4) **Recertification application.** The designated representative shall apply for recertification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The owner or operator shall submit the recertification application in accordance with § 75.60, and each complete recertification application shall include the information specified in § 75.63.
 - (5) **Approval or disapproval of request for recertification.** The procedures for provisional certification in paragraph (a)(3) of this section shall apply to recertification applications. The Administrator will issue a notice of approval, disapproval, or incompleteness according to the procedures in paragraph (a)(4) of this section. In the event that a recertification application is disapproved, data from the monitoring system are invalidated and the applicable missing data procedures in §§ 75.31 or 75.33 shall be used from the date and hour of receipt of the disapproval notice back to the hour of the adjustment or change to the CEMS that triggered the need for recertification testing or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section were used, back to the hour of the probationary calibration error test that began the recertification test period. Data from the monitoring system remain invalid until all required recertification tests have been passed or until a subsequent probationary calibration error test is passed, beginning a new recertification test period. The owner or operator shall repeat all recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the recertification retest dates, as specified in § 75.61(a)(1)(ii), and shall submit a new recertification application according to the procedures in paragraph (b)(4) of this section.
- (c) **Initial certification and recertification procedures.** Prior to the deadline in § 75.4, the owner or operator shall conduct initial certification tests and in accordance with § 75.63, the designated representative shall submit an application to demonstrate that the continuous emission or opacity monitoring system and components thereof meet the specifications in appendix A to this part. The owner or operator shall compare reference method values with output from the automated data acquisition and handling system that is part of the continuous emission monitoring system being tested. Except as otherwise specified in paragraphs (b)(1), (d), and (e) of this section, and in sections 6.3.1 and 6.3.2 of appendix A to this part, the owner or operator shall perform the following tests for initial certification or recertification of continuous emission or opacity monitoring systems or components according to the requirements of appendix A to this part:
- (1) For each SO₂ pollutant concentration monitor, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined under § 75.71(a)(2), and each NO_x-diluent continuous emission monitoring system:
 - (i) A 7-day calibration error test, where, for the NO_x-diluent continuous emission monitoring system, the test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor;
 - (ii) A linearity check, where, for the NO_x-diluent continuous emission monitoring system, the test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor;

- (iii) A relative accuracy test audit. For the NO_x-diluent continuous emission monitoring system, the RATA shall be done on a system basis, in units of lb/mmBtu. For the NO_x concentration monitoring system, the RATA shall be done on a ppm basis;
 - (iv) A bias test;
 - (v) A cycle time test, (where, for the NO_x-diluent continuous emission monitoring system, the test is performed separately on the NO_x pollutant concentration monitor and the diluent gas monitor); and
- (2) For each flow monitor:
- (i) A 7-day calibration error test;
 - (ii) Relative accuracy test audits, as follows:
 - (A) A single-load (or single-level) RATA at the normal load (or level), as defined in section 6.5.2.1(d) of appendix A to this part, for a flow monitor installed on a peaking unit or bypass stack, or for a flow monitor exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part;
 - (B) For all other flow monitors, a RATA at each of the three load levels (or operating levels) corresponding to the three flue gas velocities described in section 6.5.2(a) of appendix A to this part;
 - (iii) A bias test for the single-load (or single-level) flow RATA described in paragraph (c)(2)(ii)(A) of this section; and
 - (iv) A bias test (or bias tests) for the 3-level flow RATA described in paragraph (c)(2)(ii)(B) of this section, at the following load or operational level(s):
 - (A) At each load level designated as normal under section 6.5.2.1(d) of appendix A to this part, for units that produce electrical or thermal output, or
 - (B) At the operational level identified as normal in section 6.5.2.1(d) of appendix A to this part, for units that do not produce electrical or thermal output.
- (3) The initial certification test data from an O₂ or a CO₂ diluent gas monitor certified for use in a NO_x continuous emission monitoring system may be submitted to meet the requirements of paragraph (c)(4) of this section. Also, for a diluent monitor that is used both as a CO₂ monitoring system and to determine heat input, only one set of diluent monitor certification data need be submitted (under the component and system identification numbers of the CO₂ monitoring system).
- (4) For each CO₂ pollutant concentration monitor, each CO₂ monitoring system that uses an O₂ monitor to determine CO₂ concentration, and each diluent gas monitor used only to monitor heat input rate:
- (i) A 7-day calibration error test;
 - (ii) A linearity check;
 - (iii) A relative accuracy test audit, where, for an O₂ monitor used to determine CO₂ concentration, the CO₂ reference method shall be used for the RATA; and
 - (iv) A cycle-time test.
- (5) For each continuous moisture monitoring system consisting of wet- and dry-basis O₂ analyzers:

- (i) A 7-day calibration error test of each O₂ analyzer;
 - (ii) A cycle time test of each O₂ analyzer;
 - (iii) A linearity test of each O₂ analyzer; and
 - (iv) A RATA, directly comparing the percent moisture measured by the monitoring system to a reference method.
- (6) For each continuous moisture sensor: A RATA, directly comparing the percent moisture measured by the monitor sensor to a reference method.
- (7) For a continuous moisture monitoring system consisting of a temperature sensor and a data acquisition and handling system (DAHS) software component programmed with a moisture lookup table:
 - (i) A demonstration that the correct moisture value for each hour is being taken from the moisture lookup tables and applied to the emission calculations. At a minimum, the demonstration shall be made at three different temperatures covering the normal range of stack temperatures from low to high.
 - (ii) [Reserved]
- (8) The owner or operator shall ensure that initial certification or recertification of a continuous opacity monitor for use under the Acid Rain Program is conducted according to one of the following procedures:
 - (i) Performance of the tests for initial certification or recertification, according to the requirements of Performance Specification 1 in appendix B to part 60 of this chapter; or
 - (ii) A continuous opacity monitoring system tested and certified previously under State or other Federal requirements to meet the requirements of Performance Specification 1 shall be deemed certified for the purposes of this part.
- (9) [Reserved]
- (10) For the automated data acquisition and handling system, tests designed to verify:
 - (i) Proper computation of hourly averages for pollutant concentrations, flow rate, pollutant emission rates, and pollutant mass emissions; and
 - (ii) Proper computation and application of the missing data substitution procedures in subpart D of this part and the bias adjustment factors in section 7 of appendix A to this part.
- (11) The owner or operator shall provide adequate facilities for initial certification or recertification testing that include:
 - (i) Sampling ports adequate for test methods applicable to such facility, such that:
 - (A) Volumetric flow rate, pollutant concentration, and pollutant emission rates can be accurately determined by applicable test methods and procedures; and
 - (B) A stack or duct free of cyclonic flow during performance tests is available, as demonstrated by applicable test methods and procedures.
 - (ii) Basic facilities (e.g., electricity) for sampling and testing equipment.

(d) **Initial certification and recertification and quality assurance procedures for optional backup continuous emission monitoring systems –**

- (1) **Redundant backups.** The owner or operator of an optional redundant backup CEMS shall comply with all the requirements for initial certification and recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section. The owner or operator shall operate the redundant backup CEMS during all periods of unit operation, except for periods of calibration, quality assurance, maintenance, or repair. The owner or operator shall perform upon the redundant backup CEMS all quality assurance and quality control procedures specified in appendix B to this part, except that the daily assessments in section 2.1 of appendix B to this part are optional for days on which the redundant backup CEMS is not used to report emission data under this part. For any day on which a redundant backup CEMS is used to report emission data, the system must meet all of the applicable daily assessment criteria in appendix B to this part.
- (2) **Non-redundant backups.** The owner or operator of an optional non-redundant backup CEMS or like-kind replacement analyzer shall comply with all of the following requirements for initial certification, quality assurance, recertification, and data reporting:
 - (i) Except as provided in paragraph (d)(2)(v) of this section, for a regular non-redundant backup CEMS (i.e., a non-redundant backup CEMS that has its own separate probe, sample interface, and analyzer), or a non-redundant backup flow monitor, all of the tests in paragraph (c) of this section are required for initial certification of the system, except for the 7-day calibration error test.
 - (ii) For a like-kind replacement non-redundant backup analyzer (i.e., a non-redundant backup analyzer that uses the same probe and sample interface as a primary monitoring system), no initial certification of the analyzer is required. A non-redundant backup analyzer, connected to the same probe and interface as a primary CEMS in order to satisfy the dual span requirements of section 2.1.1.4 or 2.1.2.4 of appendix A to this part, shall be treated in the same manner as a like-kind replacement analyzer.
 - (iii) Each non-redundant backup CEMS or like-kind replacement analyzer shall comply with the daily and quarterly quality assurance and quality control requirements in appendix B to this part for each day and quarter that the non-redundant backup CEMS or like-kind replacement analyzer is used to report data, and shall meet the additional linearity and calibration error test requirements specified in this paragraph. The owner or operator shall ensure that each non-redundant backup CEMS or like-kind replacement analyzer passes a linearity check (for pollutant concentration and diluent gas monitors) or a calibration error test (for flow monitors) prior to each use for recording and reporting emissions. For a primary NO_x-diluent CEMS consisting of the primary pollutant analyzer and a like-kind replacement diluent analyzer (or vice-versa), provided that the primary pollutant or diluent analyzer (as applicable) is operating and is not out-of-control with respect to any of its quality assurance requirements, only the like-kind replacement analyzer must pass a linearity check before the system is used for data reporting. When a non-redundant backup CEMS or like-kind replacement analyzer is brought into service, prior to conducting the linearity test, a probationary calibration error test (as described in paragraph (b)(3)(ii) of this section), which will begin a period of conditionally valid data, may be performed in order to allow the validation of data retrospectively, as follows. Conditionally valid data from the CEMS or like-kind replacement analyzer are validated back to the hour of completion of the probationary calibration error test if the following conditions are met: if no adjustments are made to the CEMS or like-kind replacement analyzer other than the

allowable calibration adjustments specified in section 2.1.3 of appendix B to this part between the probationary calibration error test and the successful completion of the linearity test; and if the linearity test is passed within 168 unit (or stack) operating hours of the probationary calibration error test. However, if the linearity test is performed within 168 unit or stack operating hours but is either failed or aborted due to a problem with the CEMS or like-kind replacement analyzer, then all of the conditionally valid data are invalidated back to the hour of the probationary calibration error test, and data from the non-redundant backup CEMS or from the primary monitoring system of which the like-kind replacement analyzer is a part remain invalid until the hour of completion of a successful linearity test. Notwithstanding this requirement, the conditionally valid data status may be re-established after a failed or aborted linearity check, if corrective action is taken and a calibration error test is subsequently passed. However, in no case shall the use of conditional data validation extend for more than 168 unit or stack operating hours beyond the date and time of the original probationary calibration error test when the analyzer was brought into service.

- (iv) When data are reported from a non-redundant backup CEMS or like-kind replacement analyzer, the appropriate bias adjustment factor shall be determined as follows:
 - (A) For a regular non-redundant backup CEMS, as described in paragraph (d)(2)(i) of this section, apply the bias adjustment factor from the most recent RATA of the non-redundant backup system (even if that RATA was done more than 12 months previously); or
 - (B) When a like-kind replacement non-redundant backup analyzer is used as a component of a primary CEMS (as described in paragraph (d)(2)(ii) of this section), apply the primary monitoring system bias adjustment factor.
- (v) For each parameter monitored (*i.e.*, SO₂, CO₂, O₂, NO_x, Hg or flow rate) at each unit or stack, a regular non-redundant backup CEMS may not be used to report data at that affected unit or common stack for more than 720 hours in any one calendar year (or 720 hours in any ozone season, for sources that report emission data only during the ozone season, in accordance with § 75.74(c)), unless the CEMS passes a RATA at that unit or stack. For each parameter monitored at each unit or stack, the use of a like-kind replacement non-redundant backup analyzer (or analyzers) is restricted to 720 cumulative hours per calendar year (or ozone season, as applicable), unless the owner or operator redesignates the like-kind replacement analyzer(s) as component(s) of regular non-redundant backup CEMS and each redesignated CEMS passes a RATA at that unit or stack.
- (vi) For each regular non-redundant backup CEMS, no more than eight successive calendar quarters shall elapse following the quarter in which the last RATA of the CEMS was done at a particular unit or stack, without performing a subsequent RATA. Otherwise, the CEMS may not be used to report data from that unit or stack until the hour of completion of a passing RATA at that location.
- (vii) Each regular non-redundant backup CEMS shall be represented in the monitoring plan required under § 75.53 as a separate monitoring system, with unique system and component identification numbers. When like-kind replacement non-redundant backup analyzers are used, the owner or operator shall represent each like-kind replacement analyzer used during a particular calendar quarter in the monitoring plan required under § 75.53 as a component of a primary monitoring system. The owner or operator shall also assign a unique component identification number to each like-kind replacement analyzer, beginning with the letters "LK" (*e.g.*, "LK1," "LK2," etc.) and shall specify the manufacturer, model and serial number of the like-

kind replacement analyzer. This information may be added, deleted or updated as necessary, from quarter to quarter. The owner or operator shall also report data from the like-kind replacement analyzer using the system identification number of the primary monitoring system and the assigned component identification number of the like-kind replacement analyzer. For the purposes of the electronic quarterly report required under § 75.64, the owner or operator may manually enter the appropriate component identification number(s) of any like-kind replacement analyzer(s) used for data reporting during the quarter.

(viii) When reporting data from a certified regular non-redundant backup CEMS, use a method of determination (MODC) code of "02." When reporting data from a like-kind replacement non-redundant backup analyzer, use a MODC of "17" (see Table 4a under § 75.57). For the purposes of the electronic quarterly report required under § 75.64, the owner or operator may manually enter the required MODC of "17" for a like-kind replacement analyzer.

(3) **Reference method backups.** A monitoring system that is operated as a reference method backup system pursuant to the reference method requirements of methods 2, 6C, 7E, or 3A in appendix A of part 60 of this chapter need not perform and pass the certification tests required by paragraph (c) of this section prior to its use pursuant to this paragraph.

(e) **Certification/recertification procedures for either peaking unit or by-pass stack/duct continuous emission monitoring systems.** The owner or operator of either a peaking unit or by-pass stack/duct continuous emission monitoring system shall comply with all the requirements for certification or recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section, except as follows: the owner or operator need only perform one nine-run relative accuracy test audit for certification or recertification of a flow monitor installed on the by-pass stack/duct or on the stack/duct used only by affected peaking unit(s). The relative accuracy test audit shall be performed during normal operation of the peaking unit(s) or the by-pass stack/duct.

(f) **Certification/recertification procedures for alternative monitoring systems.** The designated representative representing the owner or operator of each alternative monitoring system approved by the Administrator as equivalent to or better than a continuous emission monitoring system according to the criteria in subpart E of this part shall apply for certification to the Administrator prior to use of the system under the Acid Rain Program, and shall apply for recertification to the Administrator following a replacement, modification, or change according to the procedures in paragraph (c) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification or recertification according to the procedures specified in paragraphs (a) and (b) of this section.

(g) **Initial certification and recertification procedures for excepted monitoring systems under appendices D and E.** The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit using the optional protocol under appendix D or E to this part shall ensure that an excepted monitoring system under appendix D or E to this part meets the applicable general operating requirements of § 75.10, the applicable requirements of appendices D and E to this part, and the initial certification or recertification requirements of this paragraph.

(1) **Initial certification and recertification testing.** The owner or operator shall use the following procedures for initial certification and recertification of an excepted monitoring system under appendix D or E to this part.

- (i) When the optional SO₂ mass emissions estimation procedure in appendix D to this part or the optional NO_x emissions estimation protocol in appendix E to this part is used, the owner or operator shall provide data from a flowmeter accuracy test (or shall provide a statement of calibration if the flowmeter meets the accuracy standard by design) for each fuel flowmeter, according to section 2.1.5.1 of appendix D to this part. For orifice, nozzle, and venturi-type flowmeters, the results of primary element visual inspections and/or calibrations of the transmitters or transducers shall also be provided.
 - (ii) For the automated data acquisition and handling system used under either the optional SO₂ mass emissions estimation procedure in appendix D of this part or the optional NO_x emissions estimation protocol in appendix E of this part, the owner or operator shall perform tests designed to verify:
 - (A) The proper computation of hourly averages for pollutant concentrations, fuel flow rates, emission rates, heat input, and pollutant mass emissions; and
 - (B) Proper computation and application of the missing data substitution procedures in appendix D or E of this part.
 - (iii) When the optional NO_x emissions protocol in appendix E is used, the owner or operator shall complete all initial performance testing under section 2.1 of appendix E.
- (2) **Initial certification, recertification, and QA testing notification.** The designated representative shall provide initial certification testing notification, recertification testing notification, and routine periodic quality-assurance testing, as specified in § 75.61. Initial certification testing notification, recertification testing notification, or periodic quality assurance testing notification is not required for an excepted monitoring system under appendix D to this part.
- (3) **Monitoring plan.** The designated representative shall submit an initial monitoring plan in accordance with § 75.62(a).
- (4) **Initial certification or recertification application.** The designated representative shall submit an initial certification or recertification application in accordance with §§ 75.60 and 75.63.
- (5) **Provisional approval of initial certification and recertification applications.** Upon the successful completion of the required initial certification or recertification procedures for each excepted monitoring system under appendix D or E to this part, each excepted monitoring system under appendix D or E to this part shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the initial certification or recertification application formal approval process in paragraph (a)(4) of this section shall apply, except that the term "excepted monitoring system" shall apply rather than "continuous emission or opacity monitoring system" and except that the procedures for loss of certification or for disapproval of a recertification request in paragraph (g)(7) of this section shall apply rather than the procedures for loss of certification or denial of a recertification request in paragraph (a)(5) or (b)(5) of this section. Data measured and recorded by a provisionally certified (or recertified) excepted monitoring system under appendix D or E to this part will be considered quality-assured data from the date and time of completion of the last initial certification or recertification test, provided that the Administrator does not revoke the provisional certification or recertification by issuing a notice of disapproval in accordance with the provisions in paragraph (a)(4) or (b)(5) of this section.

- (6) **Recertification requirements.** Recertification of an excepted monitoring system under appendix D or E to this part is required for any modification to the system or change in operation that could significantly affect the ability of the system to accurately account for emissions and for which the Administrator determines that an accuracy test of the fuel flowmeter or a retest under appendix E to this part to re-establish the NO_x correlation curve is required. Examples of such changes or modifications include fuel flowmeter replacement, changes in unit configuration, or exceedance of operating parameters.
- (7) **Procedures for loss of certification or recertification for excepted monitoring systems under appendices D and E to this part.** In the event that a certification or recertification application is disapproved for an excepted monitoring system, data from the monitoring system are invalidated, and the applicable missing data procedures in section 2.4 of appendix D or section 2.5 of appendix E to this part shall be used from the date and hour of receipt of such notice back to the hour of the provisional certification. Data from the excepted monitoring system remain invalid until all required tests are repeated and the excepted monitoring system is again provisionally certified. The owner or operator shall repeat all certification or recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the certification or recertification retest dates if required under paragraph (g)(2) of this section and shall submit a new certification or recertification application according to the procedures in paragraph (g)(4) of this section.
- (h) **Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19.** The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph.
- (1) **Monitoring plan.** The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62.
- (2) **Certification application.** The designated representative shall submit a certification application in accordance with § 75.63(a)(1)(ii).
- (3) **Approval of certification applications.** The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that "continuous emission or opacity monitoring system" shall be replaced with "low mass emissions excepted methodology." Provisional certification status for the low mass emissions methodology begins on the date of submittal (consistent with the definition of "submit" in § 72.2 of this chapter) of a complete certification application, and the methodology is considered to be certified either upon receipt of a written approval notice from the Administrator or, if such notice is not provided, at the end of the Administrator's 120-day review period. However, in contrast to CEM systems or appendix D and E monitoring systems, a provisionally certified or certified low mass emissions excepted methodology may not be used to report data under the Acid Rain Program or in a NO_x mass emissions reduction program under subpart H of this part prior to the applicable commencement date specified in § 75.19(a)(2)(i).
- (4) **Disapproval of low mass emissions unit certification applications.** If the Administrator determines that the certification application for a low mass emissions unit does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the

provisional certification is invalidated by the Administrator, and any emission data reported using the excepted methodology during the Administrator's 120-day review period shall be considered invalid. The owner or operator shall use the following procedures when a certification application is disapproved:

- (i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation in which data were reported using the low mass emissions methodology until such time, date, and hour as continuous emission monitoring systems or excepted monitoring systems, where applicable, are installed and provisionally certified: the maximum potential concentration of SO₂, as defined in section 2.1.1.1 of appendix A to this part; the maximum potential fuel flowrate, as defined in section 2.4.2 of appendix D to this part; the maximum potential values of fuel sulfur content, GCV, and density (if applicable) in Table D-6 of appendix D to this part; the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter; the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part; or the maximum potential CO₂ concentration as defined in section 2.1.3.1 of appendix A to this part. For a unit subject to a State or federal NO_x mass reduction program where the owner or operator intends to monitor NO_x mass emissions with a NO_x pollutant concentration monitor and a flow monitoring system, substitute for NO_x concentration using the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, and substitute for volumetric flow using the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part; and
 - (ii) The designated representative shall submit a notification of certification test dates for the required monitoring systems, as specified in § 75.61(a)(1)(i), and shall submit a certification application according to the procedures in paragraph (a)(2) of this section.
- (5) **Recertification.** Recertification of an approved low mass emissions excepted methodology is not required. Once the Administrator has approved the methodology for use, the owner or operator is subject to the on-going qualification and disqualification procedures in § 75.19(b), on an annual or ozone season basis, as applicable.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26524, May 17, 1995; 60 FR 40296, Aug. 8, 1995; 61 FR 59158, Nov. 20, 1996; 63 FR 57506, Oct. 27, 1998; 64 FR 28592, May 26, 1999; 67 FR 40431, June 12, 2002; 70 FR 28678, May 18, 2005; 72 FR 51527, Sept. 7, 2007; 73 FR 4345, Jan. 24, 2008; 76 FR 17308, Mar. 28, 2011]

§ 75.21 Quality assurance and quality control requirements.

- (a) **Continuous emission monitoring systems.** The owner or operator of an affected unit shall operate, calibrate and maintain each continuous emission monitoring system used to report emission data under the Acid Rain Program as follows:
 - (1) The owner or operator shall operate, calibrate and maintain each primary and redundant backup continuous emission monitoring system according to the quality assurance and quality control procedures in appendix B of this part.
 - (2) The owner or operator shall ensure that each non-redundant backup CEMS meets the quality assurance requirements of § 75.20(d) for each day and quarter that the system is used to report data.

- (3) The owner or operator shall perform quality assurance upon a reference method backup monitoring system according to the requirements of Method 2, 6C, 7E, or 3A in Appendices A-1, A-2 and A-4 to part 60 of this chapter (supplemented, as necessary, by guidance from the Administrator), instead of the procedures specified in appendix B to this part.
- (4) The owner or operator of a unit with an SO₂ continuous emission monitoring system is not required to perform the daily or quarterly assessments of the SO₂ monitoring system under appendix B to this part on any day or in any calendar quarter in which only gaseous fuel is combusted in the unit if, during those days and calendar quarters, SO₂ emissions are determined in accordance with § 75.11(e)(1). However, such assessments are permissible, and if any daily calibration error test or linearity test of the SO₂ monitoring system is failed while the unit is combusting only gaseous fuel, the SO₂ monitoring system shall be considered out-of-control. The length of the out-of-control period shall be determined in accordance with the applicable procedures in section 2.1.4 or 2.2.3 of appendix B to this part.
- (5) For a unit with an SO₂ continuous monitoring system, in which gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) is sometimes burned as a primary or backup fuel and in which higher-sulfur fuel(s) such as oil or coal are, at other times, burned as primary or backup fuel(s), the owner shall perform the relative accuracy test audits of the SO₂ monitoring system (as required by section 6.5 of appendix A to this part and section 2.3.1 of appendix B to this part) only when the higher-sulfur fuel is combusted in the unit and shall not perform SO₂ relative accuracy test audits when the very low sulfur gaseous fuel is the only fuel being combusted.
- (6) If the designated representative certifies that a unit with an SO₂ monitoring system burns only very low sulfur fuel (as defined in § 72.2 of this chapter), the SO₂ monitoring system is exempted from the relative accuracy test audit requirements in appendices A and B to this part.
- (7) If the designated representative certifies that a particular unit with an SO₂ monitoring system combusts primarily fuel(s) that are very low sulfur fuel(s) (as defined in § 72.2 of this chapter) and combusts higher sulfur fuel(s) only for infrequent, non-routine operations (e.g., only as emergency backup fuel(s) or for short-term testing), the SO₂ monitoring system shall be exempted from the RATA requirements of appendices A and B to this part in any calendar year that the unit combusts the higher sulfur fuel(s) for no more than 480 hours. If, in a particular calendar year, the higher-sulfur fuel usage exceeds 480 hours, the owner or operator shall perform a RATA of the SO₂ monitor (while combusting the higher-sulfur fuel) either by the end of the calendar quarter in which the exceedance occurs or by the end of a 720 unit (or stack) operating hour grace period (under section 2.3.3 of appendix B to this part) following the quarter in which the exceedance occurs.
- (8) The quality assurance provisions of §§ 75.11(e)(3)(i) through 75.11(e)(3)(iv) shall apply to all units with SO₂ monitoring systems during hours in which only very low sulfur fuel (as defined in § 72.2 of this chapter) is combusted in the unit.
- (9) Provided that a unit with an SO₂ monitoring system is not exempted from the SO₂ RATA requirements of this part under paragraphs (a)(6) or (a)(7) of this section, any calendar quarter during which a unit combusts only very low sulfur fuel (as defined in § 72.2 of this chapter) shall be excluded in determining the quarter in which the next relative accuracy test audit must be performed for the SO₂ monitoring system. However, no more than eight successive calendar quarters shall elapse after a relative accuracy test audit of an SO₂ monitoring system, without a subsequent relative accuracy test audit having been performed. The owner or operator shall ensure that a

relative accuracy test audit is performed, in accordance with paragraph (a)(5) of this section, either by the end of the eighth successive elapsed calendar quarter since the last RATA or by the end of a 720 unit (or stack) operating hour grace period, as provided in section 2.3.3 of appendix B to this part.

(10) The owner or operator who, in accordance with § 75.11(e)(1), uses a certified flow monitor and a certified diluent monitor and Equation F-23 in appendix F to this part to calculate SO₂ emissions during hours in which a unit combusts only natural gas or pipeline natural gas (as defined in § 72.2 of this chapter) shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor.

(b) **Continuous opacity monitoring systems.** The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous opacity monitoring system used under the Acid Rain Program according to the procedures specified for State Implementation Plans, pursuant to part 51, appendix M of this chapter.

(c) **Calibration gases.** The owner or operator shall ensure that all calibration gases used to quality assure the operation of the instrumentation required by this part shall meet the definition in § 72.2 of this chapter.

(d) **Notification for periodic relative accuracy test audits.** The owner or operator or the designated representative shall submit a written notice of the dates of relative accuracy testing as specified in § 75.61.

(e) **Consequences of audits.** The owner or operator shall invalidate data from a continuous emission monitoring system or continuous opacity monitoring system upon failure of an audit under appendix B to this part or any other audit, beginning with the unit operating hour of completion of a failed audit as determined by the Administrator. The owner or operator shall not use invalidated data for reporting either emissions or heat input, nor for calculating monitor data availability.

(1) **Audit decertification.** Whenever both an audit of a continuous emission or opacity monitoring system (or component thereof, including the data acquisition and handling system), of any excepted monitoring system under appendix D or E to this part, or of any alternative monitoring system under subpart E of this part, and a review of the initial certification application or of a recertification application, reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement of this part, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit of the facility or an audit of any information submitted to EPA or the State agency regarding the facility. By issuing the notice of disapproval, the certification status is revoked prospectively by the Administrator. The data measured and recorded by each system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the procedures in § 75.20(a)(5) for initial certification or § 75.20(b)(5) for recertification to replace, prospectively, all of the invalid, non-quality-assured data for each disapproved system.

(2) **Out-of-control period.** Whenever a continuous emission monitoring system or continuous opacity monitoring system fails a quality assurance audit or any other audit, the system is out-of-control. The owner or operator shall follow the procedures for out-of-control periods in § 75.24.

- (f) **Requirements for Air Emission Testing.** On and after March 27, 2012, relative accuracy testing under § 75.74(c)(2)(ii), section 6.5 of appendix A to this part, and section 2.3.1 of appendix B to this part, and stack testing under § 75.19 and section 2.1 of appendix E to this part shall be performed by an “Air Emission Testing Body”, as defined in § 72.2 of this chapter. Conformance to the requirements of ASTM D7036-04 (incorporated by reference, see § 75.6), referred to in section 6.1.2 of appendix A to this part, shall apply only to these tests. Section 1.1.4 of appendix B to this part, and section 2.1 of appendix E to this part require compliance with section 6.1.2 of appendix A to this part. Tests and activities under this part not required to be performed by an AETB as defined in § 72.2 of this chapter include daily CEMS operation, daily calibration error checks, daily flow interference checks, quarterly linearity checks, routine maintenance of CEMS, voluntary emissions testing, or emissions testing required under other regulations.
- (g) **Requirements for EPA Protocol Gas Verification Program.** Any EPA Protocol gas production site that chooses to participate in the EPA Protocol Gas Verification Program (PGVP) must notify the Administrator of its intent to participate. An EPA Protocol gas production site's participation shall commence immediately upon notification to EPA and shall extend through the end of the calendar year in which notification is provided. EPA will issue a vendor ID to each participating EPA Protocol gas production site. In each year of the PGVP, EPA may audit up to four EPA Protocol gas cylinders from each participating EPA Protocol gas production site.
- (1) A production site participating in the PGVP shall provide the following information in its initial and ongoing notifications to EPA in an electronic format prescribed by the Administrator (see the CAMD Web site <http://www.epa.gov/airmarkets/emissions/pgvp.html>):
- (i) The specialty gas company name which owns or operates the participating production site;
 - (ii) The name, e-mail address, and telephone number of a contact person for that specialty gas company;
 - (iii) The name and address of that participating EPA Protocol gas production site, owned or operated by the specialty gas company; and
 - (iv) The name, e-mail address, and telephone number of a contact person for that participating EPA Protocol gas production site.
- (2) An EPA Protocol gas production site that elects to continue participating in the PGVP in the next calendar year must notify the Administrator of its intent to continue in the program by December 31 of the current year by submitting to EPA the information described in paragraph (g)(1) of this section.
- (3) A list of the names, contact information, and vendor IDs of EPA Protocol gas production sites participating in the PGVP will be made publicly available by posting on EPA Web sites (see the CAMD Web site <http://www.epa.gov/airmarkets/emissions/pgvp.html>).
- (4) EPA may remove an EPA Protocol gas production site from the list of PGVP participants and give notice to the production site for any of the following reasons:
- (i) If the EPA Protocol gas production site fails to provide all of the information required by paragraph (g)(1) of this section in accordance with paragraph (g)(2) of this section;
 - (ii) If, after being notified that its EPA Protocol gas cylinders are being audited by EPA, the EPA Protocol gas production site fails to cancel its invoice or to credit the purchaser's account for the cylinders within 45 calendar days of such notification; or

- (iii) If, after being notified that its EPA Protocol gas cylinders are being audited by EPA, the EPA Protocol gas production site cannot provide to EPA upon demand proof of payment to the National Institute of Standards and Technology (NIST) and a valid contract with NIST;
- (5) EPA may relist an EPA Protocol gas production site as follows:
 - (i) An EPA Protocol gas production site may be relisted immediately after its failure is remedied if the only reason for removal from the list of PGVP participants is failure to provide all of the information required by paragraph (g)(1) of this section;
 - (ii) If EPA does not receive hardcopy or electronic proof of a credit receipt or of cancellation of the invoice for the cylinders from the EPA Protocol gas production site within 45 calendar days of notifying the EPA Protocol gas production site that its cylinders are being audited by EPA, the cylinders shall be returned to the EPA Protocol gas production site free of any demurrage, and that EPA Protocol gas production site shall not be eligible for relisting for 180 calendar days from the date of notice that it was removed from the list and until it submits to EPA the information required by paragraph (g)(1) of this section;
 - (iii) For any EPA Protocol gas production site which is notified by EPA that its cylinders are being audited and cannot provide to EPA upon demand proof of payment to NIST and a valid contract with NIST, the cylinders may either be kept by NIST or returned to the EPA Protocol gas production site free of any demurrage and at no cost to NIST, and that EPA Protocol gas production site shall not be eligible for relisting for 180 calendar days from the date of notice that it was removed from the list and until it submits to EPA the information required by paragraph (g)(1) of this section.
- (6) On and after May 27, 2011 for each unit subject to this part that uses EPA Protocol gases, the owner or operator must obtain such gases from either an EPA Protocol gas production site that is on the EPA list of sites participating in the PGVP on the date the owner or operator procures such gases or from a reseller that sells to the owner or operator unaltered EPA Protocol gases produced by an EPA Protocol gas production site that was on the EPA list of participating sites on the date the reseller procured such gases.
- (7) An EPA Protocol gas cylinder certified by or ordered from any non-participating EPA Protocol gas production site no later than May 27, 2011 may be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig. In the event that an EPA Protocol gas production site is removed from the list of PGVP participants on the same date as or after the date on which a particular cylinder has been certified or ordered, that gas cylinder may continue to be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig. However, in no case shall a cylinder described in this paragraph (g)(7) be recertified by a non-participating EPA Protocol gas production site to extend its useful life and be used by a source subject to this part.
- (8) If EPA notifies a participating EPA Protocol gas production site that its EPA Protocol gas cylinders are being audited and identifies the purchaser as an EPA representative or contractor participating in the audit process, the production site shall:
 - (i) Either cancel that purchaser's invoice or credit that purchaser's account for the purchase of those EPA Protocol gas cylinders;
 - (ii) Not charge for demurrage for those EPA Protocol gas cylinders;

- (iii) Arrange for and pay for the return shipment of its cylinders from NIST; and
- (iv) Provide sufficient funding to NIST for:
 - (A) The analysis of those EPA Protocol gas cylinders by NIST;
 - (B) The production site's pro rata share of draft and final NIST electronic audit reports as specified in paragraphs (g)(9)(ii) through (g)(9)(v) of this section on all cylinders in the current audit; and
 - (C) The full cost of a draft redacted electronic audit report containing just that production site's results and the information as specified in paragraphs (g)(9)(ii) through (g)(9)(v) of this section;
- (9) If EPA notifies a participating EPA Protocol gas production site that its EPA Protocol gas cylinders are being audited then:
 - (i) Each participating EPA Protocol gas production site must have NIST analyze its EPA Protocol gas cylinders provided for audit as soon after NIST receives the batch containing those cylinders as possible, preferably within two weeks of NIST's receipt, using analytical procedures consistent with metrology institute practices and at least as rigorous as the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards" (Traceability Protocol), September 1997, as amended August 25, 1999, EPA-600/R-97/121, (incorporated by reference, see § 75.6) or equivalent written cylinder analysis protocol that has been approved by EPA.
 - (ii) Each cylinder's concentration must be determined by NIST and the results compared to each cylinder's certification documentation and tag value to establish conformance with section 5.1 of appendix A to this part. After NIST analysis, each cylinder must be provided with a NIST analyzed concentration with an expanded uncertainty, as defined in § 72.2, (coverage factor, as defined in § 72.2, $k = 2$) of plus or minus 1.0 percent (calculated combined standard uncertainty of plus or minus 0.5%), inclusive, or better, unless otherwise approved by EPA.
 - (iii) The certification documentation accompanying each cylinder must be verified in the audit report as meeting the requirements of "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended August 25, 1999, EPA-600/R-97/121 (incorporated by reference, see § 75.6) or a revised procedure approved by the Administrator.
 - (iv) Each participating EPA Protocol gas production site shall have NIST provide all of the information required by paragraphs (g)(9)(ii) through (g)(9)(v) of this section in draft and final electronic audit reports on all cylinders in the current audit, and in a draft redacted electronic audit report containing just that production site's information. The draft audit report on all cylinders in the current audit and each draft redacted version of the audit report shall be submitted electronically by NIST to pgvp@epa.gov, unless otherwise provided by the Administrator, within four weeks of completion of all cylinder analyses or as soon as possible thereafter. The draft and final audit report on all cylinders in the current audit shall only be sent to EPA. EPA will send the applicable draft redacted audit report to each participating production site for comment. To be considered in the final posted audit report, EPA must receive comments, and any cylinder re-analyses from participating EPA Protocol gas production sites within 60 days of the participating EPA Protocol gas production site's receipt of the draft redacted audit report. All comments from production sites, including any cylinder re-analyses, on the draft redacted versions of the audit report shall be submitted electronically to

pgvp@epa.gov, unless otherwise provided by the Administrator. The final audit report on all cylinders in the current audit shall be submitted electronically by NIST to pgvp@epa.gov, unless otherwise provided by the Administrator, within 90 days of the participating EPA Protocol gas production site's receipt of the draft redacted audit report sent by EPA or as soon as possible thereafter. EPA will post the final results of the NIST analyses on EPA Web sites (see the CAMD Web site <http://www.epa.gov/airmarkets/emissions/pgvp.html>). Each audit report shall include:

- (A) A table with the information and in the format specified by Figure 3 (or the Note below Figure 3, as applicable) of appendix B to this part or such revised format as approved by the Administrator; and
 - (B) Complete documentation of the NIST procedures used to analyze the cylinders, including the analytical reference standards, analytical method, analytical method uncertainty, analytical instrumentation, and instrument calibration procedures.
- (v) For EPA Protocol gas production sites that produce EPA Protocol gas cylinders claiming NIST traceability for both NO and NO_x concentrations in the same cylinder, if analyzed by NIST for the PGVP, such cylinders must be analyzed by NIST for both the NO and NO_x components (where total NO_x is determined by NO plus NO₂) and the results of the analyses shall be included in the audit report.
- (10) An EPA Protocol gas production site shall continue to be on the EPA list of sites participating in the PGVP and may continue to sell EPA Protocol gases to sources subject to part 75 if it is not notified by EPA that its cylinders are being audited under the PGVP if it provides the information described in paragraph (g)(1) of this section in accordance with paragraph (g)(2) of this section.
- (11) The data validation procedures under §§ 2.1.4, 2.2.3, and 2.3.2 of appendix B to this part apply.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26527, 26566, May 17, 1995; 61 FR 25582, May 22, 1996; 61 FR 59159, Nov. 20, 1996; 64 FR 28599, May 26, 1999; 67 FR 40433, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 70 FR 28679, May 18, 2005; 73 FR 4345, Jan. 24, 2008; 76 FR 17308, Mar. 28, 2011]

§ 75.22 Reference test methods.

- (a) The owner or operator shall use the following methods, which are found in appendices A-1 through A-4 to part 60 of this chapter, to conduct the following tests: Monitoring system tests for certification or recertification of continuous emission monitoring Systems; NO_x emission tests of low mass emission units under § 75.19(c)(1)(iv); NO_x emission tests of excepted monitoring systems under appendix E to this part; and required quality assurance and quality control tests:
- (1) Methods 1 or 1A are the reference methods for selection of sampling site and sample traverses.
 - (2) Method 2 or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, are the reference methods for determination of volumetric flow.
 - (3) Methods 3, 3A, or 3B are the reference methods for the determination of the dry molecular weight O₂ and CO₂ concentrations in the emissions.
 - (4) Method 4 (either the standard procedure described in section 8.1 of the method or the moisture approximation procedure described in section 8.2 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For

the purpose of determining the stack gas molecular weight, however, the alternative wet bulb-dry bulb technique for approximating the stack gas moisture content described in section 2.2 of Method 4 may be used in lieu of the procedures in sections 8.1 and 8.2 of the method.

- (5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60 of this chapter, as applicable, are the reference methods for determining SO₂ and NO_x pollutant concentrations. (Methods 6A and 6B in appendix A-4 to part 60 of this chapter may also be used to determine SO₂ emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E in appendix A-4 to part 60 of this chapter must be used to measure total NO_x emissions, both NO and NO₂, for purposes of this part. The owner or operator shall not use the following sections, exceptions, and options of method 7E in appendix A-4 to part 60 of this chapter:
 - (i) Section 7.1 of the method allowing for use of prepared calibration gas mixtures that are produced in accordance with method 205 in Appendix M of 40 CFR Part 51;
 - (ii) The sampling point selection procedures in section 8.1 of the method, for the emission testing of boilers and combustion turbines under appendix E to this part. The number and location of the sampling points for those applications shall be as specified in sections 2.1.2.1 and 2.1.2.2 of appendix E to this part;
 - (iii) Paragraph (3) in section 8.4 of the method allowing for the use of a multi-hole probe to satisfy the multipoint traverse requirement of the method;
 - (iv) Section 8.6 of the method allowing for the use of "Dynamic Spiking" as an alternative to the interference and system bias checks of the method. Dynamic spiking may be conducted (optionally) as an additional quality assurance check; and
 - (v) That portion of Section 8.5 of the method allowing multiple sampling runs to be conducted before performing the post-run system bias check or system calibration error check.
- (6) Method 3A in appendix A-2 and method 7E in appendix A-4 to part 60 of this chapter are the reference methods for determining NO_x and diluent emissions from stationary gas turbines for testing under appendix E to this part.
- (b) The owner or operator may use any of the following methods, which are found in appendices A-1 through A-4 to part 60 of this chapter, as a reference method backup monitoring system to provide quality-assured monitor data:
 - (1) Method 3A for determining O₂ or CO₂ concentration;
 - (2) Method 6C for determining SO₂ concentration;
 - (3) Method 7E for determining total NO_x concentration (both NO and NO₂);
 - (4) Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part.
- (c)
 - (1) Instrumental EPA Reference Methods 3A, 6C, and 7E in appendices A-2 and A-4 of part 60 of this chapter shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

- (i) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology;
 - (ii) Approves the use of an equivalent method; or
 - (iii) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors.
- (2) Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under Section 114 of the Act.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26528, May 17, 1995; 64 FR 28600, May 26, 1999; 67 FR 40433, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 70 FR 28679, May 18, 2005; 73 FR 4345, Jan. 24, 2008; 76 FR 17310, Mar. 28, 2011]

§ 75.23 Alternatives to standards incorporated by reference.

- (a) The designated representative of a unit may petition the Administrator for an alternative to any standard incorporated by reference and prescribed in this part in accordance with § 75.66(c).
- (b) [Reserved]

[60 FR 26528, May 17, 1995]

§ 75.24 Out-of-control periods and adjustment for system bias.

- (a) If an out-of-control period occurs to a monitor or continuous emission monitoring system, the owner or operator shall take corrective action and repeat the tests applicable to the "out-of-control parameter" as described in appendix B of this part.
 - (1) For daily calibration error tests, an out-of-control period occurs when the calibration error of a pollutant concentration monitor exceeds the applicable specification in section 2.1.4 of appendix B to this part.
 - (2) For quarterly linearity checks, an out-of-control period occurs when the error in linearity at any of three gas concentrations (low, mid-range, and high) exceeds the applicable specification in appendix A to this part.
 - (3) For relative accuracy test audits, an out-of-control period occurs when the relative accuracy exceeds the applicable specification in appendix A to this part.
- (b) When a monitor or continuous emission monitoring system is out-of-control, any data recorded by the monitor or monitoring system are not quality-assured and shall not be used in calculating monitor data availabilities pursuant to § 75.32 of this part.
- (c) When a monitor or continuous emission monitoring system is out-of-control, the owner or operator shall take one of the following actions until the monitor or monitoring system has successfully met the relevant criteria in appendices A and B of this part as demonstrated by subsequent tests:
 - (1) Apply the procedures for missing data substitution to emissions from affected unit(s); or
 - (2) Use a certified backup monitoring system or a reference method for measuring and recording emissions from the affected unit(s); or

- (3) Adjust the gas discharge paths from the affected unit(s) with emissions normally observed by the out-of-control monitor or monitoring system so that all exhaust gases are monitored by a certified monitor or monitoring system meeting the requirements of appendices A and B of this part.
- (d) When the bias test indicates that an SO₂ monitor, a flow monitor, a NO_x-diluent continuous emission monitoring system, or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.4 of appendix B to this part.
- (e) The owner or operator shall determine if a continuous opacity monitoring system is out-of-control and shall take appropriate corrective actions according to the procedures specified for State Implementation Plans, pursuant to appendix M of part 51 of this chapter. The owner or operator shall comply with the monitor data availability requirements of the State. If the State has no monitor data availability requirements for continuous opacity monitoring systems, then the owner or operator shall comply with the monitor data availability requirements as stated in the data capture provisions of appendix M, part 51 of this chapter.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26528, May 17, 1995; 64 FR 28600, May 26, 1999; 67 FR 40433, June 12, 2002; 70 FR 28680, May 18, 2005; 76 FR 17311, Mar. 28, 2011]

Subpart D—Missing Data Substitution Procedures

§ 75.30 General provisions.

- (a) Except as provided in § 75.34, the owner or operator shall provide substitute data for each affected unit using a continuous emission monitoring system according to the missing data procedures in this subpart whenever the unit combusts any fuel and:
 - (1) A valid, quality-assured hour of SO₂ concentration data (in ppm) has not been measured and recorded for an affected unit by a certified SO₂ pollutant concentration monitor, or by an approved alternative monitoring method under subpart E of this part, except as provided in paragraph (d) of this section; or
 - (2) A valid, quality-assured hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or by an approved alternative monitoring system under subpart E of this part; or
 - (3) A valid, quality-assured hour of NO_x emission rate data (in lb/mmBtu) has not been measured or recorded for an affected unit, either by a certified NO_x-diluent continuous emission monitoring system or by an approved alternative monitoring system under subpart E of this part; or
 - (4) A valid, quality-assured hour of CO₂ concentration data (in percent CO₂, or percent O₂ converted to percent CO₂ using the procedures in appendix F to this part) has not been measured and recorded for an affected unit, either by a certified CO₂ continuous emission monitoring system or by an approved alternative monitoring method under subpart E of this part; or

- (5) A valid, quality-assured hour of NO_x concentration data (in ppm) has not been measured or recorded for an affected unit, either by a certified NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), or by an approved alternative monitoring system under subpart E of this part; or
 - (6) A valid, quality-assured hour of CO₂ or O₂ concentration data (in percent CO₂, or percent O₂) used for the determination of heat input has not been measured and recorded for an affected unit, either by a certified CO₂ or O₂ diluent monitor, or by an approved alternative monitoring method under subpart E of this part; or
 - (7) A valid, quality-assured hour of moisture data (in percent H₂O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §§ 75.11(b) or 75.12(b), is used to account for the hourly moisture content of the stack gas; or
 - (8) A valid, quality-assured hour of heat input rate data (in mmBtu/hr) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO₂ or O₂) monitor or by an approved alternative monitoring system under subpart E of this part.
- (b) However, the owner or operator shall have no need to provide substitute data according to the missing data procedures in this subpart if the owner or operator uses SO₂, CO₂, NO_x, or O₂ concentration, flow rate, percent moisture, or NO_x emission rate data recorded from either a certified redundant or regular non-redundant backup CEMS, a like-kind replacement non-redundant backup analyzer, or a backup reference method monitoring system when the certified primary monitor is not operating or is out-of-control. A redundant or non-redundant backup continuous emission monitoring system must have been certified according to the procedures in § 75.20 prior to the missing data period. Non-redundant backup continuous emission monitoring system must pass a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors) prior to each period of use of the certified backup monitor for recording and reporting emissions. Use of a certified backup monitoring system or backup reference method monitoring system is optional and at the discretion of the owner or operator.
- (c) When the certified primary monitor is not operating or out-of-control, then data recorded for an affected unit from a certified backup continuous emission monitor or backup reference method monitoring system are used, as if such data were from the certified primary monitor, to calculate monitor data availability in § 75.32, and to provide the quality-assured data used in the missing data procedures in §§ 75.31 and 75.33, such as the “hour after” value.
- (d) The owner or operator shall comply with the applicable provisions of this paragraph during hours in which a unit with an SO₂ continuous emission monitoring system combusts only gaseous fuel.
- (1) Whenever a unit with an SO₂ CEMS combusts only natural gas or pipeline natural gas (as defined in § 72.2 of this chapter) and the owner or operator is using the procedures in section 7 of appendix F to this part to determine SO₂ mass emissions pursuant to § 75.11(e)(1), the owner or operator shall, for purposes of reporting heat input data under § 75.57(b)(5), and for the calculation of SO₂ mass emissions using Equation F-23 in section 7 of appendix F to this part, substitute for missing data from a flow monitoring system, CO₂ diluent monitor or O₂ diluent monitor using the missing data substitution procedures in § 75.36.
 - (2) Whenever a unit with an SO₂ CEMS combusts gaseous fuel and the owner or operator uses the gas sampling and analysis and fuel flow procedures in appendix D to this part to determine SO₂ mass emissions pursuant to § 75.11(e)(2), the owner or operator shall substitute for missing total sulfur

content, gross calorific value, and fuel flowmeter data using the missing data procedures in appendix D to this part and shall also, for purposes of reporting heat input data under § 75.54(b)(5) or § 75.57(b)(5), as applicable, substitute for missing data from a flow monitoring system, CO₂ diluent monitor, or O₂ diluent monitor using the missing data substitution procedures in § 75.36.

- (3) The owner or operator of a unit with an SO₂ monitoring system shall not include hours when the unit combusts only gaseous fuel in the SO₂ data availability calculations in § 75.32 or in the calculations of substitute SO₂ data using the procedures of either § 75.31 or § 75.33, for hours when SO₂ emissions are determined in accordance with § 75.11(e)(1) or (e)(2). For the purpose of the missing data and availability procedures for SO₂ pollutant concentration monitors in §§ 75.31 and 75.33 only, all hours during which the unit combusts only gaseous fuel shall be excluded from the definition of "monitor operating hour," "quality-assured monitor operating hour," "unit operating hour," and "unit operating day," when SO₂ emissions are determined in accordance with § 75.11(e)(1) or (e)(2).
- (4) During all hours in which a unit with an SO₂ continuous emission monitoring system combusts only gaseous fuel and the owner or operator uses the SO₂ monitoring system to determine SO₂ mass emissions pursuant to § 75.11(e)(3), the owner or operator shall determine the percent monitor data availability for SO₂ in accordance with § 75.32 and shall use the standard SO₂ missing data procedures of § 75.33.

[60 FR 26528, 26566, May 17, 1995, as amended at 61 FR 59160, Nov. 20, 1996; 64 FR 28600, May 26, 1999; 67 FR 40433, June 12, 2002]

§ 75.31 Initial missing data procedures.

- (a) During the first 720 quality-assured monitor operating hours following initial certification of the required SO₂, CO₂, O₂, or moisture monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by CEMS(s) installed at that location), and during the first 2,160 quality assured monitor operating hours following initial certification of the required NO_x-diluent, NO_x concentration, or flow monitoring system(s) at the unit or stack location, the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section. The owner or operator of a unit shall use these procedures for no longer than three years (26,280 clock hours) following initial certification.
- (b) SO₂, CO₂, or O₂ concentration data, and moisture data. For each hour of missing SO₂ or CO₂ emissions concentration data (including CO₂ data converted from O₂ data using the procedures in appendix F of this part), or missing O₂ or CO₂ diluent concentration data used to calculate heat input, or missing moisture data, the owner or operator shall calculate the substitute data as follows:
 - (1) Whenever prior quality-assured data exist, the owner or operator shall substitute, by means of the data acquisition and handling system, for each hour of missing data, the average of the hourly SO₂, CO₂, or O₂ concentrations or moisture percentages recorded by a certified monitor for the unit operating hour immediately before and the unit operating hour immediately after the missing data period.
 - (2) Whenever no prior quality assured SO₂, CO₂, or O₂ concentration data or moisture data exist, the owner or operator shall substitute, as applicable, for each hour of missing data, the maximum potential SO₂ concentration or the maximum potential CO₂ concentration or the minimum potential O₂ concentration or (unless Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used to determine NO_x emission rate) the minimum potential moisture percentage, as

specified, respectively, in sections 2.1.1.1, 2.1.3.1, 2.1.3.2 and 2.1.5 of appendix A to this part. If Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used to determine NO_x emission rate, substitute the maximum potential moisture percentage, as specified in section 2.1.6 of appendix A to this part.

(c) ***Volumetric flow and NO_x emission rate or NO_x concentration data (load ranges or operational bins used).***

The procedures in this paragraph apply to affected units for which load-based ranges or non-load-based operational bins, as defined, respectively, in sections 2 and 3 of appendix C to this part are used to provide substitute NO_x and flow rate data. For each hour of missing volumetric flow rate data, NO_x emission rate data, or NO_x concentration data used to determine NO_x mass emissions:

- (1) Whenever prior quality-assured data exist in the load range (or operational bin) corresponding to the operating load (or operating conditions) at the time of the missing data period, the owner or operator shall substitute, by means of the automated data acquisition and handling system, for each hour of missing data, the arithmetic average of all of the prior quality-assured hourly flow rates, NO_x emission rates, or NO_x concentrations in the corresponding load range (or operational bin) as determined using the procedure in appendix C to this part. When non-load-based operational bins are used, if essential operating or parametric data are unavailable for any hour in the missing data period, such that the operational bin cannot be determined, the owner or operator shall, for that hour, substitute (as applicable) the maximum potential flow rate as specified in section 2.1.4.1 of appendix A to this part or the maximum potential NO_x emission rate or the maximum potential NO_x concentration as specified in section 2.1.2.1 of appendix A to this part.
- (2) This paragraph (c)(2) does not apply to non-load-based units using operational bins. Whenever no prior quality-assured flow or NO_x emission rate or NO_x concentration data exist for the corresponding load range, the owner or operator shall substitute, for each hour of missing data, the average hourly flow rate or the average hourly NO_x emission rate or NO_x concentration at the next higher level load range for which quality-assured data are available.
- (3) Whenever no prior quality-assured flow rate or NO_x emission rate or NO_x concentration data exist for the corresponding load range, or any higher load range (or for non-load-based units using operational bins, when no prior quality-assured data exist in the corresponding operational bin), the owner or operator shall, as applicable, substitute, for each hour of missing data, the maximum potential flow rate as specified in section 2.1.4.1 of appendix A to this part or shall substitute the maximum potential NO_x emission rate or the maximum potential NO_x concentration, as specified in section 2.1.2.1 of appendix A to this part. Alternatively, where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the hour, as provided in § 75.34(d), the owner or operator may substitute, as applicable, the maximum controlled NO_x emission rate (MCR) or the maximum expected NO_x concentration (MEC).

(d) ***Non-load-based volumetric flow and NO_x emission rate or NO_x concentration data (operational bins not used).*** The procedures in this paragraph, (d), apply only to affected units that do not produce electrical output (in megawatts) or thermal output (in klb/hr of steam) and for which operational bins are not used. For each hour of missing volumetric flow rate data, NO_x emission rate data, or NO_x concentration data used to determine NO_x mass emissions:

- (1) Whenever prior quality-assured data exist at the time of the missing data period, the owner or operator shall substitute, by means of the automated data acquisition and handling system, for each hour of missing data, the arithmetic average of all of the prior quality-assured hourly average flow rates or NO_x emission rates or NO_x concentrations.

- (2) Whenever no prior quality-assured flow rate, NO_x emission rate, or NO_x concentration data exist, the owner or operator shall, as applicable, substitute for each hour of missing data, the maximum potential flow rate as specified in section 2.1.4.1 of appendix A to this part or the maximum potential NO_x emission rate or the maximum potential NO_x concentration as specified in section 2.1.2.1 of appendix A to this part.

[64 FR 28601, May 26, 1999, as amended at 67 FR 40433, June 12, 2002; 70 FR 28680, May 18, 2005; 73 FR 4346, Jan. 24, 2008; 76 FR 17311, Mar. 28, 2011]

§ 75.32 Determination of monitor data availability for standard missing data procedures.

- (a) Following initial certification of the required SO₂, CO₂, O₂, or moisture monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by CEMS(s) at that location), the owner or operator shall begin calculating the percent monitor data availability as described in paragraph (a)(1) of this section, and shall, upon completion of the first 720 quality-assured monitor operating hours, record, by means of the automated data acquisition and handling system, the percent monitor data availability for each monitored parameter. Similarly, following initial certification of the required NO_x-diluent, NO_x concentration, or flow monitoring system(s) at a unit or stack location, the owner or operator shall begin calculating the percent monitor data availability as described in paragraph (a)(1) of this section, and shall, upon completion of the first 2,160 quality-assured monitor operating hours, record, by means of the automated data acquisition and handling system, the percent monitor data availability for each monitored parameter. Notwithstanding these requirements, if three years (26,280 clock hours) have elapsed since the date and hour of initial certification and fewer than 720 (or 2,160, as applicable) quality-assured monitor operating hours have been recorded, the owner or operator shall begin recording the percent monitor data availability. The percent monitor data availability shall be calculated for each monitored parameter at each unit or stack location, as follows:
- (1) Prior to completion of 8,760 unit or stack operating hours following initial certification, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 8 to calculate, hourly, percent monitor data availability.

$$\text{Percent monitor data availability} = \frac{\text{Total unit operating hours for which quality-assured data were recorded since certification}}{\text{Total unit operating hours since certification}} \times 100 \quad (\text{Eq. 8})$$

- (2) Upon completion of 8,760 unit (or stack) operating hours following initial certification and thereafter, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 9 to calculate hourly, percent monitor data availability. Notwithstanding this requirement, if three years (26,280 clock hours) have elapsed since initial certification and fewer than 8,760 unit or stack operating hours have been accumulated, the owner or operator shall begin using a modified version of Equation 9, as described in paragraph (a)(3) of this section.

$$\text{Percent monitor data availability} = \frac{\text{Total unit operating hours for which quality-assured data were recorded during previous 8,760 unit operating hours}}{8,760} \times 100 \quad (\text{Eq. 9})$$

(3) When calculating percent monitor data availability using Equation 8 or 9, the owner or operator shall include all unit operating hours, and all monitor operating hours for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part. No hours from more than three years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated fewer than 8,760 unit operating hours in the previous three years (26,280 clock hours), replace the words "during previous 8,760 unit operating hours" in the numerator of Equation 9 with "in the previous three years" and replace "8,760" in the denominator of Equation 9 with "total unit operating hours in the previous three years." The owner or operator of a unit with an SO₂ monitoring system shall, when SO₂ emissions are determined in accordance with § 75.11(e)(1) or (e)(2), exclude hours in which a unit combusts only gaseous fuel from calculations of percent monitor data availability for SO₂ pollutant concentration monitors, as provided in § 75.30(d).

(b) The monitor data availability shall be calculated for each hour during each missing data period. The owner or operator shall record the percent monitor data availability for each hour of each missing data period to implement the missing data substitution procedures.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26529, 26567, May 17, 1995; 61 FR 59160, Nov. 20, 1996; 64 FR 28602, May 26, 1999; 67 FR 40434, June 12, 2002; 70 FR 28680, May 18, 2005; 73 FR 4346, Jan. 24, 2008; 76 FR 17311, Mar. 28, 2011]

§ 75.33 Standard missing data procedures for SO₂, NO_x, and flow rate.

(a) Following initial certification of the required SO₂, NO_x, and flow rate monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality-assured data begins to be recorded by CEMS(s) at that location) and upon completion of the first 720 quality-assured monitor operating hours (for SO₂) or the first 2,160 quality-assured monitor operating hours (for flow, NO_x emission rate, or NO_x concentration), the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section and depicted in Table 1 (SO₂) and Table 2 of this section (NO_x, flow). The owner or operator may either implement the provisions of paragraphs (b) and (c) of this section on a non-fuel-specific basis, or may, as described in paragraphs (b)(5), (b)(6), (c)(7) and (c)(8) of this section, provide fuel-specific substitute data values. Notwithstanding these requirements, if three years (26,280 clock hours) have elapsed since the date and hour of initial certification, and fewer than 720 (or 2,160, as applicable) quality-assured monitor operating hours have been recorded, the owner or operator shall begin using the missing data procedures of this section. The owner or operator of a unit shall substitute for missing data using quality-assured monitor operating hours of data from no earlier than three years (26,280 clock hours) prior to the date and time of the missing data period.

(b) **SO₂ concentration data.** For each hour of missing SO₂ concentration data,

(1) If the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:

- (i) For a missing data period less than or equal to 24 hours, substitute the average of the hourly SO₂ concentrations recorded by an SO₂ pollutant concentration monitor for the hour before and the hour after the missing data period.
 - (ii) For a missing data period greater than 24 hours, substitute the greater of:
 - (A) The 90th percentile hourly SO₂ concentration recorded by an SO₂ pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
 - (B) The average of the hourly SO₂ concentrations recorded by an SO₂ pollutant concentration monitor for the hour before and the hour after the missing data period.
- (2) If the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:
 - (i) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly SO₂ concentrations recorded by an SO₂ pollutant concentration monitor for the hour before and the hour after the missing data period.
 - (ii) For a missing data period of more than 8 hours, substitute the greater of:
 - (A) the 95th percentile hourly SO₂ concentration recorded by an SO₂ pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
 - (B) The average of the hourly SO₂ concentrations recorded by an SO₂ pollutant concentration monitor for the hour before and the hour after the missing data period.
- (3) If the monitor data availability is at least 80.0 percent but less than 90.0 percent, the owner or operator shall substitute for that hour of the missing data period the maximum hourly SO₂ concentration recorded by an SO₂ pollutant concentration monitor during the previous 720 quality-assured monitor operating hours.
- (4) If the monitor data availability is less than 80.0 percent, the owner or operator shall substitute for that hour of the missing data period the maximum potential SO₂ concentration, as defined in section 2.1.1.1 of appendix A to this part.
- (5) For units that combust more than one type of fuel, the owner or operator may opt to implement the missing data routines in paragraphs (b)(1) through (b)(4) of this section on a fuel-specific basis. If this option is selected, the owner or operator shall document this in the monitoring plan required under § 75.53.
- (6) Use the following guidelines to implement paragraphs (b)(1) through (b)(4) of this section on a fuel-specific basis:
 - (i) Separate the historical, quality-assured SO₂ concentration data according to the type of fuel combusted;
 - (ii) For units that co-fire different types of fuel, either group the co-fired hours with the historical data for the fuel with the highest SO₂ emission rate (e.g., if diesel oil and pipeline natural gas are co-fired, count co-fired hours as oil-burning hours), or separate the co-fired hours from the single-fuel hours;

- (iii) For the purposes of providing substitute data under paragraph (b)(4) of this section, determine a separate, fuel-specific maximum potential SO₂ concentration (MPC) value for each type of fuel combusted in the unit, in a manner consistent with section 2.1.1.1 of appendix A to this part. For fuel that qualifies as pipeline natural gas or natural gas (as defined in § 72.2 of this chapter), the owner or operator shall, for the purposes of determining the MPC, either determine the maximum total sulfur content and minimum gross calorific value (GCV) of the gas by fuel sampling and analysis or shall use a default total sulfur content of 0.05 percent by weight (dry basis) and a default GCV value of 950 Btu/scf. For co-firing, the MPC value shall be based on the fuel with the highest SO₂ emission rate. The exact methodology used to determine each fuel-specific MPC value shall be documented in the monitoring plan for the unit or stack; and
- (iv) For missing data periods that require 720-hour (or, if applicable, 3-year) lookbacks, use historical data for the type of fuel combusted during each hour of the missing data period to determine the appropriate substitute data value for that hour. For co-fired missing data hours, if the historical data are separated into single-fuel and co-fired hours, use co-fired data to provide the substitute data values. Otherwise, use data for the fuel with the highest SO₂ emission rate to provide substitute data values for co-fired missing data hours.

(7) Table 1 summarizes the provisions of paragraphs (b)(1) through (b)(6) of this section.

- (c) **Volumetric flow rate, NO_x emission rate and NO_x concentration data.** Use the procedures in this paragraph to provide substitute NO_x and flow rate data for all affected units for which load-based ranges have been defined in accordance with section 2 of appendix C to this part. For units that do not produce electrical or thermal output (i.e., non-load-based units), use the procedures in this paragraph only to provide substitute data for volumetric flow rate, and only if operational bins have been defined for the unit, as described in section 3 of appendix C to this part. Otherwise, use the applicable missing data procedures in paragraph (d) or (e) of this section for non-load-based units. For each hour of missing volumetric flow rate data, NO_x emission rate data, or NO_x concentration data used to determine NO_x mass emissions:

- (1) If the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:
 - (i) For a missing data period less than or equal to 24 hours, substitute, as applicable, for each missing hour, the arithmetic average of the flow rates or NO_x emission rates or NO_x concentrations recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part.
 - (ii) For a missing data period greater than 24 hours, substitute, as applicable, for each missing hour, the greater of:
 - (A) The 90th percentile hourly flow rate or the 90th percentile NO_x emission rate or the 90th percentile NO_x concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part; or
 - (B) The average of the recorded hourly flow rates, NO_x emission rates or NO_x concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

- (2) If the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:
 - (i) For a missing data period of less than or equal to 8 hours, substitute, as applicable, the arithmetic average hourly flow rate or NO_x emission rate or NO_x concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part.
 - (ii) For a missing data period greater than 8 hours, substitute, as applicable, for each missing hour, the greater of:
 - (A) The 95th percentile hourly flow rate or the 95th percentile NO_x emission rate or the 95th percentile NO_x concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part; or
 - (B) The average of the hourly flow rates, NO_x emission rates or NO_x concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.
- (3) If the monitor data availability is at least 80.0 percent but less than 90.0 percent, the owner or operator shall, by means of the automated data acquisition and handling system, substitute, as applicable, for that hour of the missing data period, the maximum hourly flow rate or the maximum hourly NO_x emission rate or the maximum hourly NO_x concentration recorded during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part.
- (4) If the monitor data availability is less than 80.0 percent, the owner or operator shall substitute, as applicable, for that hour of the missing data period, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum NO_x emission rate, as defined in section 2.1.2.1 of appendix A to this part, or the maximum potential NO_x concentration, as defined in section 2.1.2.1 of appendix A to this part. In addition, when non-load-based operational bins are used, the owner or operator shall substitute the maximum potential flow rate for any hour in the missing data period in which essential operating or parametric data are unavailable and the operational bin cannot be determined.
- (5) This paragraph, (c)(5), does not apply to non-load-based, affected units using operational bins. Whenever no prior quality-assured flow rate data, NO_x concentration data or NO_x emission rate data exist for the corresponding load range, the owner or operator shall substitute, as applicable, for each hour of missing data, the maximum hourly flow rate or the maximum hourly NO_x concentration or maximum hourly NO_x emission rate at the next higher level load range for which quality-assured data are available.
- (6) Whenever no prior quality-assured flow rate data, NO_x concentration data or NO_x emission rate data exist at either the corresponding load range (or a higher load range) or at the corresponding operational bin, the owner or operator shall substitute, as applicable, either the maximum potential NO_x emission rate or the maximum potential NO_x concentration, as defined in section 2.1.2.1 of appendix A to this part or the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part.

- (7) This paragraph (c)(7) does not apply to affected units using non-load-based operational bins. For units that combust more than one type of fuel, the owner or operator may opt to implement the missing data routines in paragraphs (c)(1) through (c)(6) of this section on a fuel-specific basis. If this option is selected, the owner or operator shall document this in the monitoring plan required under § 75.53.
- (8) This paragraph, (c)(8), does not apply to affected units using non-load-based operational bins. Use the following guidelines to implement paragraphs (c)(1) through (c)(6) of this section on a fuel-specific basis:
 - (i) Separate the historical, quality-assured NO_x emission rate, NO_x concentration, or flow rate data according to the type of fuel combusted;
 - (ii) For units that co-fire different types of fuel, either group the co-fired hours with the historical data for the fuel with the highest NO_x emission rate, NO_x concentration or flow rate, or separate the co-fired hours from the single-fuel hours;
 - (iii) For the purposes of providing substitute data under paragraph (c)(4) of this section, a separate, fuel-specific maximum potential concentration (MPC), maximum potential NO_x emission rate (MER), or maximum potential flow rate (MPF) value (as applicable) shall be determined for each type of fuel combusted in the unit, in a manner consistent with § 72.2 of this chapter and with section 2.1.2.1 or 2.1.4.1 of appendix A to this part. For co-firing, the MPC, MER or MPF value shall be based on the fuel with the highest emission rate or flow rate (as applicable). Furthermore, for a unit with add-on NO_x emission controls, a separate fuel-specific maximum controlled NO_x emission rate (MCR) or maximum expected NO_x concentration (MEC) value (as applicable) shall be determined for each type of fuel combusted in the unit. The exact methodology used to determine each fuel-specific MPC, MER, MEC, MCR or MPF value shall be documented in the monitoring plan for the unit or stack.
 - (iv) For missing data periods that require 2,160-hour (or, if applicable, 3-year) lookbacks, use historical data for the type of fuel combusted during each hour of the missing data period to determine the appropriate substitute data value for that hour. For co-fired missing data hours, if the historical data are separated into single-fuel and co-fired hours, use co-fired data to provide

the substitute data values. Otherwise, use data for the fuel with the highest NO_x emission rate, NO_x concentration or flow rate (as applicable) to provide substitute data values for co-fired missing data hours. Tables 1 and 2 follow.

TABLE 1—MISSING DATA PROCEDURE FOR SO₂ CEMS, CO₂ CEMS, MOISTURE CEMS, AND DILUENT (CO₂ OR O₂) MONITORS FOR HEAT INPUT DETERMINATION

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ²	Method	Lookback period
95 or more	N ≤24	Average	HB/HA.
	N >24	For SO ₂ , CO ₂ , and H ₂ O **, the greater of:	
		Average	HB/HA.
		90th percentile	720 hours. *
90 or more, but below 95	N ≤8	For O ₂ and H ₂ O ^X , the lesser of:	HB/HA.
		10th percentile	720 hours. *
	N >8	Average	HB/HA.
		For SO ₂ , CO ₂ , and H ₂ O **, the greater of:	
	Average	HB/HA.	
	95th percentile	720 hours. *	

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, during unit operation. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than 3 years prior to the missing data period.

¹ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled concentration from the previous 720 quality-assured monitor operating hours.

² During unit operating hours.

³ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, the unit may report the greater of: (a) the maximum expected SO₂ concentration or (b) 1.25 times the maximum controlled value from the previous 720 quality-assured monitor operating hours (see § 75.34).

^X Use this algorithm for moisture except when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

** Use this algorithm for moisture only when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ²	Method	Lookback period
80 or more, but below 90	N >0	For O ₂ and H ₂ O ^X , the lesser of: Average 5th Percentile	HB/HA. 720 hours. *
		For SO ₂ , CO ₂ , and H ₂ O **, Maximum value ¹	720 hours. *
		For O ₂ and H ₂ O ^X : Minimum value ¹	720 hours. *
Below 80	N >0	Maximum potential concentration ³ or % (for SO ₂ , CO ₂ , and H ₂ O**) or Minimum potential concentration or % (for	None.

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, during unit operation. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than 3 years prior to the missing data period.

¹ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled concentration from the previous 720 quality-assured monitor operating hours.

² During unit operating hours.

³ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, the unit may report the greater of: (a) the maximum expected SO₂ concentration or (b) 1.25 times the maximum controlled value from the previous 720 quality-assured monitor operating hours (see § 75.34).

^X Use this algorithm for moisture except when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

** Use this algorithm for moisture only when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ²	Method	Lookback period
		O ₂ and H ₂ O ^x)	

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, during unit operation. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than 3 years prior to the missing data period.

¹ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled concentration from the previous 720 quality-assured monitor operating hours.

² During unit operating hours.

³ Where a unit with add-on SO₂ emission controls can demonstrate that the controls are operating properly during the missing data period, the unit may report the greater of: (a) the maximum expected SO₂ concentration or (b) 1.25 times the maximum controlled value from the previous 720 quality-assured monitor operating hours (see § 75.34).

^x Use this algorithm for moisture except when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

** Use this algorithm for moisture only when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A-7 to part 60 of this chapter is used for NO_x emission rate.

TABLE 2—LOAD-BASED MISSING DATA PROCEDURE FOR NO_x-DILUENT CEMS, NO_x CONCENTRATION CEMS AND FLOW RATE CEMS

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ²	Method	Lookback period	Load ranges
95 or more	N ≤24	Average	2,160 hours *	Yes.
	N >24	The greater of: Average 90th percentile	HB/HA 2,160 hours *	No. Yes.
90 or more, but below 95	N ≤8	Average	2,160 hours *	Yes.
	N >8	The greater of: Average 95th percentile	HB/HA 2,160 hours *	No. Yes.
80 or more, but below 90	N >0	Maximum value ¹	2,160 hours *	Yes.

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, using data at the corresponding load range ("load bin") for each hour of the missing data period. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

¹ Where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_x concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_x mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

² During unit operating hours.

³ Alternatively, where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_x concentration (or maximum controlled NO_x emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding load bin, from the previous 2,160 quality-assured monitor operating hours.

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ²	Method	Lookback period	Load ranges
Below 80	N > 0	Maximum potential NO _x emission rate ³ ; or maximum potential NO _x concentration ³ ; or maximum potential flow rate	None	No.

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, using data at the corresponding load range ("load bin") for each hour of the missing data period. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

¹ Where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_x concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_x mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

² During unit operating hours.

³ Alternatively, where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_x concentration (or maximum controlled NO_x emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding load bin, from the previous 2,160 quality-assured monitor operating hours.

(9) The load-based provisions of paragraphs (c)(1) through (c)(8) of this section are summarized in Table 2 of this section. The non-load-based provisions for volumetric flow rate, found in paragraphs (c)(1) through (c)(4), and (c)(6) of this section, are presented in Table 4 of this section.

(d) **Non-load-based** NO_x emission rate and NO_x concentration data. Use the procedures in this paragraph to provide substitute NO_x data for affected units that do not produce electrical output (in megawatts) or thermal output (in klb/hr of steam). For each hour of missing NO_x emission rate data, or NO_x concentration data used to determine NO_x mass emissions:

(1) If the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:

(i) For a missing data period less than or equal to 24 hours, substitute, as applicable, for each missing hour, the arithmetic average of the NO_x emission rates or NO_x concentrations recorded by a monitoring system in a 2,160 hour lookback period. The lookback period may be comprised of either:

- (A) The previous 2,160 quality-assured monitor operating hours, or
 - (B) The previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins, as defined in section 3 of appendix C to this part, are used.
 - (ii) For a missing data period greater than 24 hours, substitute, for each missing hour, the 90th percentile NO_x emission rate or the 90th percentile NO_x concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).
- (2) If the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for that hour of the missing data period according to the following procedures:
- (i) For a missing data period of less than or equal to eight hours, substitute, as applicable, the arithmetic average of the hourly NO_x emission rates or NO_x concentrations recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).
 - (ii) For a missing data period greater than eight hours, substitute, for each missing hour, the 95th percentile hourly flow rate or the 95th percentile NO_x emission rate or the 95th percentile NO_x concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).
- (3) If the monitor data availability is at least 80.0 percent but less than 90.0 percent, the owner or operator shall, by means of the automated data acquisition and handling system, substitute, as applicable, for that hour of the missing data period, the maximum hourly NO_x emission rate or the maximum hourly NO_x concentration recorded during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).
- (4) If the monitor data availability is less than 80.0 percent, the owner or operator shall substitute, as applicable, for that hour of the missing data period, the maximum NO_x emission rate, as defined in § 72.2 of this chapter, or the maximum potential NO_x concentration, as defined in section 2.1.2.1 of appendix A to this part. In addition, when operational bins are used, the owner or operator shall substitute (as applicable) the maximum potential NO_x emission rate or the maximum potential NO_x concentration for any hour in the missing data period in which essential operating or parametric data are unavailable and the operational bin cannot be determined.
- (5) If operational bins are used and no prior quality-assured NO_x concentration data or NO_x emission rate data exist for the corresponding operational bin, the owner or operator shall substitute, as applicable, either the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, or the maximum potential NO_x concentration, as defined in section 2.1.2.1 of appendix A to this part.
- (6) Table 3 of this section summarizes the provisions of paragraphs (d)(1) through (d)(5) of this section.
- (e) *Non-load-based volumetric flow rate data.*

- (1) If operational bins, as defined in section 3 of appendix C to this part, are used for a unit that does not produce electrical or thermal output, use the missing data procedures in paragraph (c) of this section to provide substitute volumetric flow rate data for the unit.
- (2) If operational bins are not used, modify the procedures in paragraph (c) of this section as follows:
 - (i) In paragraphs (c)(1) through (c)(3), the words “previous 2,160 quality-assured monitor operating hours” shall apply rather than “previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part;”
 - (ii) The last sentence in paragraph (c)(4) does not apply;
 - (iii) Paragraphs (c)(5), (c)(7), and (c)(8) are not applicable; and
 - (iv) In paragraph (c)(6), the words, “for either the corresponding load range (or a higher load range) or at the corresponding operational bin” do not apply.

- (3) Table 4 of this section summarizes the provisions of paragraphs (e)(1) and (e)(2) of this section. Tables 3 and 4 follow:

TABLE 3—NON-LOAD-BASED MISSING DATA PROCEDURE FOR NO_x-DILUENT CEMS AND NO_x CONCENTRATION CEMS

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ¹	Method	Lookback period
95 or more	N ≤24	Average	2,160 hours. *
	N >24	90th percentile	2,160 hours. *
90 or more, but below 95	N ≤8	Average	2,160 hours. *
	N >8	95th percentile	2,160 hours. *
80 or more, but below 90	N >0	Maximum value ³	2,160 hours. *
Below 80, or operational bin	N >0	Maximum potential NO _x emission rate ² or maximum potential NO _x concentration ²	None.

* If operational bins are used, the lookback period is 2,160 quality-assured, monitor operating hours, and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

¹ During unit operation.

² Alternatively, where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_x concentration, (or maximum controlled NO_x emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding operational bin (if applicable), from the previous 2,160 quality-assured monitor operating hours.

³ Where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_x concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_x mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ¹	Method	Lookback period
indeterminable			

** If operational bins are used, the lookback period is 2,160 quality-assured, monitor operating hours, and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.*

¹ During unit operation.

² Alternatively, where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_x concentration, (or maximum controlled NO_x emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding operational bin (if applicable), from the previous 2,160 quality-assured monitor operating hours.

³ Where a unit with add-on NO_x emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_x concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_x mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

TABLE 4—NON-LOAD-BASED MISSING DATA PROCEDURE FOR FLOW RATE CEMS

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ¹	Method	Lookback period
95 or more	N ≤24	Average	2160 hours*
	N >24	The greater of:	

** If operational bins are used, the lookback period is the previous 2,160 quality-assured, monitor operating hours and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured, monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.*

¹ During unit operation.

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) ¹	Method	Lookback period
90 or more, but below 95	N ≤ 8	Average 90th percentile	HB/HA 2160 hours*
	N > 8	Average	2160 hours*
80 or more, but below 90	N > 0	The greater of: Average 95th percentile HB/HA 2160 hours*	2160 hours*
Below 80, or operational bin indeterminable	N > 0	Maximum value Maximum potential flow rate	2160 hours* None

** If operational bins are used, the lookback period is the previous 2,160 quality-assured, monitor operating hours and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured, monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.*

¹ During unit operation.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26529, May 17, 1995; 61 FR 25582, May 22, 1996; 64 FR 28602, May 26, 1999; 67 FR 40434, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 67 FR 57274, Sept. 9, 2002; 70 FR 28680, May 18, 2005; 73 FR 4346, Jan. 24, 2008; 76 FR 17311, Mar. 28, 2011]

§ 75.34 Units with add-on emission controls.

- (a) The owner or operator of an affected unit equipped with add-on SO₂ and/or NO_x emission controls shall provide substitute data in accordance with paragraphs (a)(1), through (a)(5) of this section for each hour in which quality-assured data from the outlet SO₂ and/or NO_x monitoring system(s) are not obtained.
- (1) The owner or operator may use the missing data substitution procedures specified in §§ 75.31 through 75.33 to provide substitute data for any missing data hour(s) in which the add-on emission controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall, for each missing data period, record parametric data to verify the proper operation of the SO₂ or NO_x add-on emission controls during each hour, as described in paragraph (d) of this section. For any missing data hour(s) in which such parametric data are either not provided or, if provided, do not demonstrate that proper operation of the SO₂ or NO_x add-on emission controls has been maintained, the owner or operator shall

substitute (as applicable) the maximum potential NO_x concentration (MPC) as defined in section 2.1.2.1 of appendix A to this part, the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, or the maximum potential concentration for SO₂, as defined by section 2.1.1.1. Alternatively, for SO₂ or NO_x, the owner or operator may substitute, if available, the hourly SO₂ or NO_x concentration recorded by a certified inlet monitor, in lieu of the MPC. For each hour in which data from an inlet monitor are reported, the owner or operator shall use a method of determination code (MODC) of "22" (see Table 4a in § 75.57). In addition, under § 75.64(c), the designated representative shall submit as part of each electronic quarterly report, a certification statement, verifying the proper operation of the SO₂ or NO_x add-on emission control for each missing data period in which the missing data procedures of §§ 75.31 through 75.33 were applied; or

- (2) This paragraph, (a)(2), applies only to a unit which, as provided in § 75.74(a) or § 75.74(b)(1), reports NO_x mass emissions on a year-round basis under a state or Federal NO_x mass emissions reduction program that adopts the emissions monitoring provisions of this part. If the add-on NO_x emission controls installed on such a unit are operated only during the ozone season or are operated in a more efficient manner during the ozone season than outside the ozone season, the owner or operator may implement the missing data provisions of paragraph (a)(1) of this section in the following alternative manner:
 - (i) The historical, quality-assured NO_x emission rate or NO_x concentration data may be separated into two categories, i.e., data recorded inside the ozone season and data recorded outside the ozone season;
 - (ii) For the purposes of the missing data lookback periods described under §§ 75.33 (c)(1), (c)(2), (c)(3) and (c)(5) of this section, the substitute data values shall be taken from the appropriate database, depending on the date(s) and hour(s) of the missing data period. That is, if the missing data period occurs inside the ozone season, the ozone season data shall be used to provide substitute data. If the missing data period occurs outside the ozone season, data from outside the ozone season shall be used to provide substitute data.
 - (iii) A missing data period that begins outside the ozone season and continues into the ozone season shall be considered to be two separate missing data periods, one ending on April 30, hour 23, and the other beginning on May 1, hour 00;
 - (iv) For missing data hours outside the ozone season, the procedures of § 75.33 may be applied unconditionally, i.e., documentation of the operational status of the emission controls is not required in order to apply the standard missing data routines.
- (3) For each missing data hour in which the percent monitor data availability for SO₂ or NO_x, calculated in accordance with § 75.32, is less than 90.0 percent and is greater than or equal to 80.0 percent; and parametric data establishes that the add-on emission controls were operating properly (i.e. within the range of operating parameters provided in the quality assurance/quality control program) during the hour, the owner or operator may:
 - (i) Replace the maximum SO₂ concentration recorded in the 720 quality-assured monitor operating hours immediately preceding the missing data period, with the maximum controlled SO₂ concentration recorded in the previous 720 quality-assured monitor operating hours; or

- (ii) Replace the maximum NO_x concentration(s) or NO_x emission rate(s) from the appropriate load bin(s) (based on a lookback through the 2,160 quality-assured monitor operating hours immediately preceding the missing data period), with the maximum controlled NO_x concentration(s) or emission rate(s) from the appropriate load bin(s) in the same 2,160 quality-assured monitor operating hour lookback period.
- (4) The designated representative may petition the Administrator under § 75.66 for approval of site-specific parametric monitoring procedure(s) for calculating substitute data for missing SO₂ pollutant concentration, NO_x pollutant concentration, and NO_x emission rate data in accordance with the requirements of paragraphs (b) and (c) of this section and appendix C to this part. The owner or operator shall record the data required in appendix C to this part, pursuant to § 75.58(b).
- (5) For each missing data hour in which the percent monitor data availability for SO₂ or NO_x, calculated in accordance with § 75.32, is below 80.0 percent and parametric data establish that the add-on emission controls were operating properly (*i.e.* within the range of operating parameters provided in the quality assurance/quality control program), in lieu of reporting the maximum potential value, the owner or operator may substitute, as applicable, the greater of:
 - (i) The maximum expected SO₂ concentration or 1.25 times the maximum hourly controlled SO₂ concentration recorded in the previous 720 quality-assured monitor operating hours;
 - (ii) The maximum expected NO_x concentration or 1.25 times the maximum hourly controlled NO_x concentration recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;
 - (iii) The maximum controlled hourly NO_x emission rate (MCR) or 1.25 times the maximum hourly controlled NO_x emission rate recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;
 - (iv) For the purposes of implementing the missing data options in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, the maximum expected SO₂ and NO_x concentrations shall be determined, respectively, according to sections 2.1.1.2 and 2.1.2.2 of appendix A to this part. The MCR shall be calculated according to the basic procedure described in section 2.1.2.1(b) of appendix A to this part, except that the words “maximum potential NO_x emission rate (MER)” shall be replaced with the words “maximum controlled NO_x emission rate (MCR)” and the NO_x MEC shall be used instead of the NO_x MPC.
- (b) For an affected unit equipped with add-on SO₂ emission controls, the designated representative may petition the Administrator to approve a parametric monitoring procedure, as described in appendix C of this part, for calculating substitute SO₂ concentration data for missing data periods. The owner or operator shall use the procedures in §§ 75.31, 75.33, or 75.34(a) for providing substitute data for missing SO₂ concentration data unless a parametric monitoring procedure has been approved by the Administrator.
 - (1) Where the monitor data availability is 90.0 percent or more for an outlet SO₂ pollutant concentration monitor, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.
 - (2) Where the monitor data availability for an outlet SO₂ pollutant concentration monitor is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedures in § 75.34(a) (1) or (2), even if the Administrator has approved a parametric monitoring procedure.

- (c) For an affected unit with NO_x add-on emission controls, the designated representative may petition the Administrator to approve a parametric monitoring procedure, as described in appendix C of this part, in order to calculate substitute NO_x emission rate data for missing data periods. The owner or operator shall use the procedures in § 75.31 or 75.33 for providing substitute data for missing NO_x emission rate data prior to receiving the Administrator's approval for a parametric monitoring procedure.
 - (1) Where monitor data availability for a NO_x continuous emission monitoring system is 90.0 percent or more, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.
 - (2) Where monitor data availability for a NO_x continuous emission monitoring system is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedure in § 75.34(a) (1) or (2), even if the Administrator has approved a parametric monitoring procedure.
- (d) In order to implement the options in paragraphs (a)(1), (a)(3) and (a)(5) of this section; and §§ 75.31(c)(3) and 75.72(c)(3), the owner or operator shall keep records of information as described in § 75.58(b)(3) to verify the proper operation of all add-on SO₂ or NO_x emission controls, during all periods of SO₂ or NO_x emission missing data. If the owner or operator elects to implement the missing data option in paragraph (a)(2) of this section, the records in § 75.58(b)(3) are required to be kept only for the ozone season. The owner or operator shall document in the quality assurance/quality control (QA/QC) program required by section 1 of appendix B to this part, the parameters monitored and (as applicable) the ranges and combinations of parameters that indicate proper operation of the controls. The owner or operator shall provide the information recorded under § 75.58(b)(3) and the related QA/QC program information to the Administrator, to the EPA Regional Office, or to the appropriate State or local agency, upon request.

[60 FR 26567, May 17, 1995, as amended at 61 FR 59160, Nov. 20, 1996; 64 FR 28604, May 26, 1999; 67 FR 40438, June 12, 2002; 73 FR 4348, Jan. 24, 2008; 76 FR 17312, Mar. 28, 2011]

§ 75.35 Missing data procedures for CO₂..

- (a) The owner or operator of a unit with a CO₂ continuous emission monitoring system for determining CO₂ mass emissions in accordance with § 75.10 (or an O₂ monitor that is used to determine CO₂ concentration in accordance with appendix F to this part) shall substitute for missing CO₂ pollutant concentration data using the procedures of paragraphs (b) and (d) of this section.
- (b) During the first 720 quality-assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality-assured data begins to be recorded by a CEMS at that location), or (when implementing these procedures for a previously certified CO₂ monitoring system) during the 720 quality-assured monitor operating hours preceding implementation of the standard missing data procedures in paragraph (d) of this section, the owner or operator shall provide substitute CO₂ pollutant concentration data or substitute CO₂ data for heat input determination, as applicable, according to the procedures in § 75.31(b).
- (c) [Reserved]
- (d) Upon completion of 720 quality-assured monitor operating hours using the initial missing data procedures of § 75.31(b), the owner or operator shall provide substitute data for CO₂ concentration or substitute CO₂ data for heat input determination, as applicable, in accordance with the procedures in § 75.33(b) except that the term "CO₂ concentration" shall apply rather than "SO₂ concentration," the term "CO₂ pollutant

concentration monitor” or “CO₂ diluent monitor” shall apply rather than “SO₂ pollutant concentration monitor,” and the term “maximum potential CO₂ concentration, as defined in section 2.1.3.1 of appendix A to this part” shall apply, rather than “maximum potential SO₂ concentration.”

[67 FR 40439, June 12, 2002]

§ 75.36 Missing data procedures for heat input rate determinations.

- (a) When hourly heat input rate is determined using a flow monitoring system and a diluent gas (O₂ or CO₂) monitor, substitute data must be provided to calculate the heat input whenever quality-assured data are unavailable from the flow monitor, the diluent gas monitor, or both. When flow rate data are unavailable, substitute flow rate data for the heat input rate calculation shall be provided according to § 75.31 or § 75.33, as applicable. When diluent gas data are unavailable, the owner or operator shall provide substitute O₂ or CO₂ data for the heat input rate calculations in accordance with paragraphs (b) and (d) of this section.
- (b) During the first 720 quality-assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality-assured data begins to be recorded by a CEMS at that location), or (when implementing these procedures for a previously certified CO₂ or O₂ monitor) during the 720 quality-assured monitor operating hours preceding implementation of the standard missing data procedures in paragraph (d) of this section, the owner or operator shall provide substitute CO₂ or O₂ data, as applicable, for the calculation of heat input (under section 5.2 of appendix F to this part) according to § 75.31(b).
- (c) [Reserved]
- (d) Upon completion of 720 quality-assured monitor operating hours using the initial missing data procedures of § 75.31(b), the owner or operator shall provide substitute data for CO₂ or O₂ concentration to calculate heat input rate, as follows. Substitute CO₂ data for heat input rate determinations shall be provided according to § 75.35(d). Substitute O₂ data for the heat input rate determinations shall be provided in accordance with the procedures in § 75.33(b), except that the term “O₂ concentration” shall apply rather than the term “SO₂ concentration” and the term “O₂ diluent monitor” shall apply rather than the term “SO₂ pollutant concentration monitor.” In addition, the term “substitute the lesser of” shall apply rather than “substitute the greater of,” the terms “minimum hourly O₂ concentration” and “minimum potential O₂ concentration, as determined under section 2.1.3.2 of appendix A to this part” shall apply rather than, respectively, the terms “maximum hourly SO₂ concentration” and “maximum potential SO₂ concentration, as determined under section 2.1.1.1 of appendix A to this part;” and the terms “10th percentile” and “5th percentile” shall apply rather than, respectively, the terms “90th percentile” and “95th percentile” (see Table 1 of § 75.33).

[60 FR 26530, May 17, 1995, as amended at 64 FR 28604, May 26, 1999; 67 FR 40439, June 12, 2002]

§ 75.37 Missing data procedures for moisture.

- (a) The owner or operator of a unit with a continuous moisture monitoring system shall substitute for missing moisture data using the procedures of this section.
- (b) Where no prior quality-assured moisture data exist, substitute the minimum potential moisture percentage, from section 2.1.5 of appendix A to this part, except when Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate. If Equation

19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, substitute the maximum potential moisture percentage, as specified in section 2.1.6 of appendix A to this part.

- (c) During the first 720 quality-assured monitor operating hours following initial certification at a particular unit or stack location (*i.e.*, the date and time at which quality-assured data begins to be recorded by a moisture monitoring system at that location), the owner or operator shall provide substitute data for moisture according to § 75.31(b).
- (d) Upon completion of the first 720 quality-assured monitor operating hours following initial certification, the owner or operator shall provide substitute data for moisture as follows:
 - (1) Unless Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, follow the missing data procedures in § 75.33(b), except that the term “moisture percentage” shall apply rather than “SO₂ concentration;” the term “moisture monitoring system” shall apply rather than the term “SO₂ pollutant concentration monitor;” the term “substitute the lesser of” shall apply rather than “substitute the greater of;” the terms “minimum hourly moisture percentage” and “minimum potential moisture percentage, as determined under section 2.1.5 of appendix A to this part” shall apply rather than, respectively, the terms “maximum hourly SO₂ concentration” and “maximum potential SO₂ concentration, as determined under section 2.1.1.1 of appendix A to this part;” and the terms “10th percentile” and “5th percentile” shall apply rather than, respectively, the terms “90th percentile” and “95th percentile” (see Table 1 of § 75.33).
 - (2) When Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate:
 - (i) Provided that none of the following equations is used to determine SO₂ emissions, CO₂ emissions or heat input: Equation F-2, F-14b, F-16, F-17, or F-18 in appendix F to this part, or Equation 19-5 or 19-9 in Method 19 in appendix A to part 60 of this chapter, use the missing data procedures in § 75.33(b), except that the term “moisture percentage” shall apply rather than “SO₂ concentration;” the term “moisture monitoring system” shall apply rather than “SO₂ pollutant concentration monitor;” and the term “maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part” shall apply, rather than “maximum potential SO₂ concentration;” or
 - (ii) If any of the following equations is used to determine SO₂ emissions, CO₂ emissions or heat input: Equation F-2, F-14b, F-16, F-17, or F-18 in appendix F to this part, or Equation 19-5 or 19-9 in Method 19 in appendix A to part 60 of this chapter, the owner or operator shall petition the Administrator under § 75.66(l) for permission to use an alternative moisture missing data procedure.

[64 FR 28604, May 26, 1999, as amended at 67 FR 40439, June 12, 2002]

§§ 75.38-75.39 [Reserved]

Subpart E—Alternative Monitoring Systems

§ 75.40 General demonstration requirements.

- (a) The owner or operator of an affected unit, or the owner or operator of an affected unit and representing a class of affected units which meet the criteria specified in § 75.47, required to install a continuous emission monitoring system may apply to the Administrator for approval of an alternative monitoring system (or system component) to determine average hourly emission data for SO₂, NO_x, and/or volumetric flow by demonstrating that the alternative monitoring system has the same or better precision, reliability, accessibility, and timeliness as that provided by the continuous emission monitoring system.
- (b) The requirements of this subpart shall be met by the alternative monitoring system when compared to a contemporaneously operating, fully certified continuous emission monitoring system or a contemporaneously operating reference method, where the appropriate reference methods are listed in § 75.22.

§ 75.41 Precision criteria.

- (a) **Data collection and analysis.** To demonstrate precision equal to or better than the continuous emission monitoring system, the owner or operator shall conduct an F-test, a correlation analysis, and a t-test for bias as described in this section. The t-test shall be performed only on sample data at the normal operating level and primary fuel supply, whereas the F-test and the correlation analysis must be performed on each of the data sets required under paragraphs (a)(4) and (a)(5) of this section. The owner or operator shall collect and analyze data according to the following requirements:
 - (1) Data from the alternative monitoring system and the continuous emission monitoring system shall be collected and paired in a manner that ensures each pair of values applies to hourly average emissions during the same hour.
 - (2) An alternative monitoring system that directly measures emissions shall have probes or other measuring devices in locations that are in proximity to the continuous emission monitoring system and shall provide data on the same parameters as those measured by the continuous emission monitoring system. Data from the alternative monitoring system shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in appendix A of this part.
 - (3) An alternative monitoring system that indirectly quantifies emission values by measuring inputs, operating characteristics, or outputs and then applying a regression or another quantitative technique to estimate emissions, shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in appendix A of this part.
 - (4) For flow monitor alternatives, the alternative monitoring system must provide sample data for each of three different exhaust gas velocities while the unit or units, if more than one unit exhausts into the stack or duct, is burning its primary fuel at:
 - (i) A frequently used low operating level, selected within the range between the minimum safe and stable operating level and 50 percent of the maximum operating level,
 - (ii) A frequently used high operating level, selected within the range between 80 percent of the maximum operating level and the maximum operating level, and
 - (iii) The normal operating level, or an evenly spaced intermediary level between low and high levels used if the normal operating level is within a specified range (10.0 percent of the maximum operating level), of either paragraphs (a)(4) (i) or (ii) of this section.

- (5) For pollutant concentration monitor alternatives, the alternative monitoring system shall provide sample data for the primary fuel supply and for all alternative fuel supplies that have significantly different sulfur content.
- (6) For the normal unit operating level and primary fuel supply, paired hourly sample data shall be provided for at least 90.0 percent of the hours during 720 unit operating hours. For each of the remaining two operating levels for flow monitor alternatives, and for each alternative fuel supply for pollutant concentration monitor alternatives, paired hourly sample data shall be provided for at least 24 successive unit operating hours.
- (7) The owner or operator shall not use missing data substitution procedures to provide sample data.
- (8) If the collected data meet the requirements of the F-test, the correlation test, and the t-test at one or more, but not all, of the operating levels or fuel supplies, the owner or operator may elect to continue collecting the paired data for up to 1,440 additional operating hours and repeat the statistical tests using the data for the entire 30- to 90-day period.
- (9) The owner or operator shall provide two separate time series data plots for the data at each operating level or fuel supply described in paragraphs (a)(4) and (a)(5) of this section. Each data plot shall have a horizontal axis that represents the clock hour and calendar date of the readings and shall contain a separate data point for every hour for the duration of the performance evaluation. The data plots shall show the following:
 - (i) Percentage difference versus time where the vertical axis represents the percentage difference between each paired hourly reading generated by the continuous emission monitoring system (or reference method) and the alternative emission monitoring system as calculated using the following equation:

$$\Delta e = \frac{e_p - e_v}{e_v} \times 100\%$$

(Eq. 10)

where,

Δe = Percentage difference between the readings generated by the alternative monitoring system and the continuous emission monitoring system.

e_p = Measured value from the alternative monitoring system.

e_v = Measured value from the continuous emission monitoring system.

- (ii) Alternative monitoring system readings and continuous emission monitoring system (or reference method) readings versus time where the vertical axis represents hourly pollutant concentrations or volumetric flow, as appropriate, and two different symbols are used to represent the readings from the alternative monitoring system and the continuous emission monitoring system (or reference method), respectively.

(b) **Data screening and calculation adjustments.** In preparation for conducting the statistical tests described in paragraph (c) of this section, the owner or operator may screen the data for lognormality and time dependency autocorrelation. If either is detected, the owner or operator shall make the following calculation adjustments:

(1) **Lognormality.** The owner or operator shall conduct any screening and adjustment for lognormality according to the following procedures.

(i) Apply the log transformation to each measured value of either the certified continuous emissions monitoring system or certified flow monitor, using the following equation:

$$l_v = \ln e_v$$

(Eq. 11)

where,

e_v = Hourly value generated by the certified continuous emissions monitoring system or certified flow monitoring system

l_v = Hourly lognormalized data values for the certified monitoring system

and to each measured value, e_p , of the proposed alternative monitoring system, using the following equation to obtain the lognormalized data values, l_p :

$$l_p = \ln e_p$$

(Eq. 12)

where,

e_p = Hourly value generated by the proposed alternative monitoring system.

l_p = Hourly lognormalized data values for the proposed alternative monitoring system.

(ii) Separately test each set of transformed data, l_v and l_p , for normality, using the following:

(A) Shapiro-Wilk test;

(B) Histogram of the transformed data; and

(C) Quantile-Quantile plot of the transformed data.

(iii) The transformed data in a data set will be considered normally distributed if all of the following conditions are satisfied:

(A) The Shapiro-Wilk test statistic, W , is greater than or equal to 0.75 or is not statistically significant at $\alpha = 0.05$.

(B) The histogram of the data is unimodal and symmetric.

(C) The Quantile-Quantile plot is a diagonal straight line.

- (iv) If both of the transformed data sets, I_v and I_p , meet the conditions for normality, specified in paragraphs (b)(1)(iii) (A) through (C) of this section, the owner or operator may use the transformed data, I_v and I_p , in place of the original measured data values in the statistical tests for alternative monitoring systems as described in paragraph (c) of this section and in appendix A of this part.
- (v) If the transformed data are used in the statistical tests in paragraph (c) of this section and in appendix A of this part, the owner or operator shall provide the following:
 - (A) Copy of the original measured values and the corresponding transformed data in printed and electronic format.
 - (B) Printed copy of the test results and plots described in paragraphs (b)(1) (i) through (iii) of this section.
- (2) **Time dependency (autocorrelation).** The screening and adjustment for time dependency are conducted according to the following procedures:
 - (i) Calculate the degree of autocorrelation of the data on their LAG1 values, where the degree of autocorrelation is represented by the Pearson autocorrelation coefficient, ρ , computed from an AR(1) autoregression model, such that:

$$\rho = \frac{COV(x'_i, x''_i)}{s_{x'_i} s_{x''_i}}$$

(Eq. 13)

where,

x'_i = The original data value at hour i .

x''_i = The LAG1 data value at hour i .

$COV(x'_i, x''_i)$ = The autocovariance of x'_i and defined by,

$$COV(x'_i, x''_i) = \frac{\sum_{i=1}^n (x'_i - \bar{x}') (x''_i - \bar{x}'')}{(n-1)}$$

(Eq. 14)

where,

n = The total number of observations in which both the original value, x'_i , and the lagged value, x''_i , are available in the data set.

s'_{x_i} = The standard deviation of the original data values, x'_i defined by,

$$s_{x'_i} = \sqrt{\frac{\sum_{i=1}^n (x'_i - \bar{x}')^2}{n-1}}$$

(Eq. 15)

where,

s''_{x_i} = The standard deviation of the LAG1 data values, x''_i , defined by

$$s_{x''_i} = \sqrt{\frac{\sum_{i=1}^n (x''_i - \bar{x}'')^2}{n-1}}$$

(Eq. 16)

where,

$\bar{x}'$ = The mean of the original data values, x'_i defined by

$$\bar{x}' = \frac{\sum_{i=1}^n x'_i}{n}$$

(Eq. 17)

where,

$\bar{x}''$ = The mean of the LAG1 data values, x''_i , defined by

$$\bar{x}'' = \frac{\sum_{i=1}^n x''_i}{n}$$

(Eq. 18)

where,

- (ii) The data in a data set will be considered autocorrelated if the autocorrelation coefficient, ρ , is significant at the 5 percent significance level. To determine if this condition is satisfied, calculate Z using the following equation:

$$Z = 0.5 \left[\ln \left(\frac{1+\rho}{1-\rho} \right) \right] \sqrt{n-3}$$

(Eq. 19)

If $Z > 1.96$, then the autocorrelation coefficient, ρ , is significant at the 5 percent significance level ($\alpha = 0.05$).

- (iii) If the data in a data set satisfy the conditions for autocorrelation, specified in paragraph (b)(2)(ii) of this section, the variance of the data, S^2 , may be adjusted using the following equation:

$$S^2_{\text{ADJ}} = VIF \times S^2$$

(Eq. 20)

where,

S^2 = The original, unadjusted variance of the data set.

VIF = The variance inflation factor, defined by

$$VIF = \frac{1}{\left[1 - \frac{2\rho}{(n-1)(1-\rho)} + \frac{2\rho(1-\rho^n)}{n(n-1)(1-\rho)^2} \right]}$$

(Eq. 21)

S^2_{ADJ} = The autocorrelation-adjusted variance for the data set.

- (iv) The procedures described in paragraphs (b)(2)(i)-(iii) of this section may be separately applied to the following data sets in order to derive distinct autocorrelation coefficients and variance inflation factors for each data set:
- (A) The set of measured hourly values, e_v , generated by the certified continuous emissions monitoring system or certified flow monitoring system.
 - (B) The set of hourly values, e_p , generated by the proposed alternative monitoring system,
 - (C) The set of hourly differences, $e_v - e_p$, between the hourly values, e_v , generated by the certified continuous emissions monitoring system or certified flow monitoring system and the hourly values, e_p , generated by the proposed alternative monitoring system.
- (v) For any data set, listed in paragraph (b)(2)(iv) of this section, that satisfies the conditions for autocorrelation specified in paragraph (b)(2)(ii) of this section, the owner or operator may adjust the variance of that data set, using equation 20 of this section.
- (A) The adjusted variance may be used in place of the corresponding original variance, as calculated using equation 23 of this section, in the F-test (Equation 24) of this section.
 - (B) In place of the standard error of the mean,

$$\frac{S_d}{\sqrt{n}}$$

in the bias test Equation A-9 of appendix A of this part the following adjusted standard error of the mean may be used:

$$\left(\frac{S_d}{\sqrt{n}}\right)_{adj} = \left[\sqrt{\left(\frac{1+\rho}{1-\rho}\right) - \left(\frac{2\rho(1-\rho^n)}{n(1-\rho)^2}\right)} \right] \times \sqrt{VIF} \times \left(\frac{S_d}{\sqrt{n}}\right)$$

(Eq. 22)where

$$\left(\frac{S_d}{\sqrt{n}}\right)_{adj} = \text{The autocorrelation-adjusted standard error of the mean.}$$

(vi) For each data set in which a variance adjustment is used, the owner or operator shall provide the following:

- (A) All values in the data set in printed and electronic format.
- (B) Values of the autocorrelation coefficient, its level of significance, the variance inflation factor, and the unadjusted original and adjusted values found in equations 20 and 22 of this section.
- (C) Equation and related statistics of the AR(1) autoregression model of the data set.
- (D) Printed documentation of the intermediate calculations used to derive the autocorrelation coefficient and the Variance Inflation Factor.

(c) **Statistical Tests.** The owner or operator shall perform the F-test and correlation analysis as described in this paragraph and the t-test for bias described in appendix A of this part to demonstrate the precision of the alternative monitoring system.

(1) **F-test.** The owner or operator shall conduct the F-test according to the following procedures.

- (i) Calculate the variance of the certified continuous emission monitoring system or certified flow monitor as applicable, S_v^2 , and the proposed method, S_p^2 , using the following equation.

$$S^2 = \frac{\sum_{i=1}^n (e_i - e_m)^2}{n-1}$$

(Eq. 23)

where,

e_i = Measured values of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method.

e_m = Mean of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method values.

n = Total number of paired samples.

- (ii) Determine if the variance of the proposed method is significantly different from that of the certified continuous emission monitoring system or certified flow monitor, as applicable, by calculating the F-value using the following equation.

$$F = \frac{S_p^2}{S_v^2}$$

(Eq. 24)

Compare the experimental F-value with the critical value of F at the 95-percent confidence level with $n-1$ degrees of freedom. The critical value is obtained from a table for F-distribution. If the calculated F-value is greater than the critical value, the proposed method is unacceptable.

- (2) **Correlation analysis.** The owner or operator shall conduct the correlation analysis according to the following procedures.

- (i) Plot each of the paired emissions readings as a separate point on a graph where the vertical axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the alternative monitoring system and the horizontal axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the continuous emission monitoring system (or reference method). On the graph, draw a horizontal line representing the mean value, e_p , for the alternative monitoring system and a vertical line representing the mean value, e_v , for the continuous emission monitoring system where,

$$\overline{e_p} = \frac{\sum e_p}{n}$$

(Eq. 25)

$$\overline{e_v} = \frac{\sum e_v}{n}$$

(Eq. 26)

where,

e_p = Hourly value generated by the alternative monitoring system.

e_v = Hourly value generated by the continuous emission monitoring system.

n = Total number of hours for which data were generated for the tests.

A separate graph shall be produced for the data generated at each of the operating levels or fuel supplies described in paragraphs (a)(4) and (a)(5) of this section.

- (ii) Use the following equation to calculate the coefficient of correlation, r , between the emissions data from the alternative monitoring system and the continuous emission monitoring system using all hourly data for which paired values were available from both monitoring systems.

$$r = \frac{\sum e_p e_v - \left(\sum e_p \right) \left(\sum e_v \right) / n}{\left(\left[\sum e_p^2 - \left(\sum e_p \right)^2 / n \right] \left[\sum e_v^2 - \left(\sum e_v \right)^2 / n \right] \right)^{1/2}} \quad (\text{Eq. 27})$$

(Eq. 27)

- (iii) If the calculated r -value is less than 0.8, the proposed method is unacceptable.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26530, May 17, 1995; 60 FR 40296, Aug. 8, 1995; 67 FR 40440, June 12, 2002]

§ 75.42 Reliability criteria.

To demonstrate reliability equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system is capable of providing valid 1-hr averages for 95.0 percent or more of unit operating hours over a 1-yr period and that the system meets the applicable requirements of appendix B of this part.

§ 75.43 Accessibility criteria.

To demonstrate accessibility equal to or better than the continuous emission monitoring system, the owner or operator shall provide reports and onsite records of emission data to demonstrate that the alternative monitoring system provides data meeting the requirements of subparts F and G of this part.

§ 75.44 Timeliness criteria.

To demonstrate timeliness equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system can meet the requirements of subparts F and G of this part; can provide a continuous, quality-assured, permanent record of certified emissions data on an hourly basis; and can issue a record of data for the previous day within 24 hours.

§ 75.45 Daily quality assurance criteria.

The owner or operator shall either demonstrate that daily tests equivalent to those specified in appendix B of this part can be performed on the alternative monitoring system or demonstrate and document that such tests are unnecessary for providing quality-assured data.

§ 75.46 Missing data substitution criteria.

The owner or operator shall demonstrate that all missing data can be accounted for in a manner consistent with the applicable missing data procedures in subpart D of this part.

§ 75.47 Criteria for a class of affected units.

- (a) The owner or operator of an affected unit may represent a class of affected units for the purpose of applying to the Administrator for a class-approved alternative monitoring system.
- (b) The owner or operator of an affected unit representing a class of affected units shall provide the following information:
 - (1) A description of the affected unit and how it appropriately represents the class of affected units;
 - (2) A description of the class of affected units, including data describing all of the affected units that will comprise the class.

[60 FR 40297, Aug. 8, 1995, as amended at 76 FR 17312, Mar. 28, 2011]

§ 75.48 Petition for an alternative monitoring system.

- (a) The designated representative shall submit the following information in the application for certification or recertification of an alternative monitoring system.
 - (1) Source identification information.
 - (2) A description of the alternative monitoring system.
 - (3) Data, calculations, and results of the statistical tests, specified in § 75.41(c) of this part, including:
 - (i) Date and hour.
 - (ii) Hourly test data for the alternative monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.
 - (iii) Hourly test data for the continuous emissions monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.
 - (iv) Arithmetic mean of the alternative monitoring system measurement values, as specified in Equation 25 in § 75.41(c) of this part, of the continuous emission monitoring system values, as specified in Equation 26 in § 75.41(c) of this part, and of their differences.
 - (v) Standard deviation of the difference, as specified in equation A-8 in appendix A of this part.
 - (vi) Confidence coefficient, as specified in equation A-9 in appendix A of this part.
 - (vii) The bias test results as specified in § 7.6.4 in appendix A of this part.
 - (viii) Variance of the measured values for the alternative monitoring system and of the measured values for the continuous emission monitoring system, as specified in Equation 23 in § 75.41(c) of this part.
 - (ix) F-statistic, as specified in Equation 24 in § 75.41(c) of this part.
 - (x) Critical value of F at the 95-percent confidence level with n-1 degrees of freedom.
 - (xi) Coefficient of correlation, r, as specified in Equation 27 in § 75.41(c) of this part.
 - (4) Data plots, specified in §§ 75.41(a)(9) and 75.41(c)(2)(i) of this part.
 - (5) Results of monitor reliability analysis.

- (6) Results of monitor accessibility analysis.
- (7) Results of monitor timeliness analysis.
- (8) A detailed description of the process used to collect data, including location and method of ensuring an accurate assessment of operating hourly conditions on a real-time basis.
- (9) A detailed description of the operation, maintenance, and quality assurance procedures for the alternative monitoring system as required in appendix B of this part.
- (10) A description of methods used to calculate heat input or diluent gas concentration, if applicable.
- (11) Results of tests and measurements (including the results of all reference method field test sheets, charts, laboratory analyses, example calculations, or other data as appropriate) necessary to substantiate that the alternative monitoring system is equivalent in performance to an appropriate, certified operating continuous emission monitoring system.

(b) [Reserved]

[60 FR 40297, Aug. 8, 1995, as amended at 64 FR 28605, May 26, 1999]

Subpart F—Recordkeeping Requirements

§§ 75.50-75.52 [Reserved]

§ 75.53 Monitoring plan.

(a) General provisions.

- (1) The provisions of paragraphs (e) and (f) of this section shall be met through December 31, 2008. The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section through December 31, 2008, except as otherwise provided in paragraph (g) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of this section only. In addition, the provisions in paragraphs (g) and (h) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009.
- (2) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (f) or (h) of this section (as applicable), a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all unit SO₂ emissions, NO_x emissions, CO₂ emissions, and opacity are monitored and reported.

(b) Whenever the owner or operator makes a replacement, modification, or change in the certified CEMS, continuous opacity monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan, by the applicable deadline specified in § 75.62 or elsewhere in this part.

(c)-(d) [Reserved]

(e) **Contents of the monitoring plan.** Each monitoring plan shall contain the information in paragraph (e)(1) of this section in electronic format and the information in paragraph (e)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) **Electronic.**

- (i) ORISPL numbers developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by EPA, if the facility does not have an ORSPL number), for all affected units involved in the monitoring plan, with the following information for each unit:
 - (A) Short name;
 - (B) Classification of the unit as one of the following: Phase I (including substitution or compensating units), Phase II, new, or nonaffected;
 - (C) Type of boiler (or boilers for a group of units using a common stack);
 - (D) Type of fuel(s) fired by boiler, fuel type start and end dates, primary/secondary/emergency/startup fuel indicator, and, if more than one fuel, the fuel classification of the boiler;
 - (E) Type(s) of emission controls for SO₂, NO_x, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; control equipment code, installation date, and optimization date; control equipment retirement date (if applicable); primary/secondary controls indicator; and an indicator for whether the controls are an original installation;
 - (F) Maximum hourly heat input capacity;
 - (G) Date of first commercial operation;
 - (H) Unit retirement date (if applicable);
 - (I) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr, rounded to the nearest 100 lb/hr);
 - (J) Identification of all units using a common stack;
 - (K) Activation date for the stack/pipe;
 - (L) Retirement date of the stack/pipe (if applicable); and
 - (M) Indicator of whether the stack is a bypass stack.
- (ii) For each unit and parameter required to be monitored, identification of monitoring methodology information, consisting of monitoring methodology, type of fuel associated with the methodology, primary/secondary methodology indicator, missing data approach for the methodology, methodology start date, and methodology end date (if applicable).
- (iii) The following information:
 - (A) Program(s) for which the EDR is submitted;
 - (B) Unit classification;

- (C) Reporting frequency;
 - (D) Program participation date;
 - (E) State regulation code (if applicable); and
 - (F) State or local regulatory agency code.
- (iv) Identification and description of each monitoring system component (including each monitor and its identifiable components, such as analyzer and/or probe) in the CEMS (e.g., SO₂ pollutant concentration monitor, flow monitor, moisture monitor; NO_x pollutant concentration monitor, and diluent gas monitor), the continuous opacity monitoring system, or the excepted monitoring system (e.g., fuel flowmeter, data acquisition and handling system), including:
 - (A) Manufacturer, model number and serial number;
 - (B) Component/system identification code assigned by the utility to each identifiable monitoring component (such as the analyzer and/or probe). Each code shall use a three-digit format, unique to each monitoring component and unique to each monitoring system;
 - (C) Designation of the component type and method of sample acquisition or operation, (e.g., in situ pollutant concentration monitor or thermal flow monitor);
 - (D) Designation of the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e);
 - (E) First and last dates the system reported data;
 - (F) Status of the monitoring component; and
 - (G) Parameter monitored.
- (v) Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:
 - (A) Hardware components that perform emission calculations or store data for quarterly reporting purposes (provide the manufacturer and model number); and
 - (B) Software components (provide the identification of the provider and model/version number).
- (vi) Explicit formulas for each measured emission parameter, using component/system identification codes for the primary system used to measure the parameter that links CEMS or excepted monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix D or E to this part. Formulas for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). The formulas must contain all constants and factors required to derive mass emissions or emission rates from component/system code observations and an indication of whether the formula is being added, corrected, deleted, or is unchanged. Each emissions formula is identified with a unique three digit code. The owner or operator of a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) is not required to report such formulas.

- (vii) Inside cross-sectional area (ft²) at flue exit (for all units) and at flow monitoring location (for units with flow monitors, only).
- (viii) Stack exit height (ft) above ground level and ground level elevation above sea level.
- (ix) Monitoring location identification, facility identification code as assigned by the Administrator for use under the Acid Rain Program or this part, and the following information, as reported to the Energy Information Administration (EIA): facility identification number, flue identification number, boiler identification number, ARP/Subpart H facility ID number or ORISPL number (as applicable), reporting year, and 767 reporting indicator (or equivalent).
- (x) For each parameter monitored: Scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculation), maximum potential NO_x emission rate, span value, full-scale range, daily calibration units of measure, span effective date/hour, span inactivation date/hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO₂, NO_x, CO₂, O₂, or flow component monitors.
- (xi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter:
 - (A) Identification of the parameter;
 - (B) Default, maximum, minimum, or constant value, and units of measure for the value;
 - (C) Purpose of the value;
 - (D) Indicator of use during controlled/uncontrolled hours;
 - (E) Type of fuel;
 - (F) Source of the value;
 - (G) Value effective date and hour;
 - (H) Date and hour value is no longer effective (if applicable); and
 - (I) For units using the excepted methodology under § 75.19, the applicable SO₂ emission factor.
- (xii) Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit of common stack on which hardware CEMS are installed:
 - (A) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, or thousands of lb/hr of steam, or ft/sec (as applicable);
 - (B) The load or operating level(s) designated as normal in section 6.5.2.1 of appendix A to this part, expressed in megawatts, or thousands of lb/hr of steam, or ft/sec (as applicable);
 - (C) The two load or operating levels (i.e., low, mid, or high) identified in section 6.5.2.1 of appendix A to this part as the most frequently used;

- (D) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels; and
 - (E) Activation and deactivation dates, when the normal load or operating level(s) or two most frequently-used load or operating levels change and are updated.
- (xiii) For each unit for which the optional fuel flow-to-load test in section 2.1.7 of appendix D to this part is used:
- (A) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts or thousands of lb/hr of steam;
 - (B) The load level designated as normal, pursuant to section 6.5.2.1 of appendix A to this part, expressed in megawatts or thousands of lb/hr of steam; and
 - (C) The date of the load analysis used to determine the normal load level.
- (xiv) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:
- (A) Stack or duct width at the test location, ft;
 - (B) Stack or duct depth at the test location, ft;
 - (C) Wall effects adjustment factor (WAF), to the nearest 0.0001;
 - (D) Method of determining the WAF;
 - (E) WAF Effective date and hour;
 - (F) WAF no longer effective date and hour (if applicable);
 - (G) WAF determination date;
 - (H) Number of WAF test runs;
 - (I) Number of Method 1 traverse points in the WAF test;
 - (J) Number of test ports in the WAF test; and
 - (K) Number of Method 1 traverse points in the reference flow RATA.

(2) **Hardcopy.**

- (i) Information, including (as applicable): identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_x emission rate, and span; and apportionment strategies under §§ 75.10 through 75.18.
- (ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of this section and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.
- (iii) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.

- (iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitor components, and stacks corresponding to the identification numbers provided in paragraphs (e)(1)(i), (e)(1)(iv), (e)(1)(vi), and (e)(1)(ix) of this section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.
- (v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.
- (f) **Contents of monitoring plan for specific situations.** The following additional information shall be included in the monitoring plan for the specific situations described:
 - (1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO₂ mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_x emission rate (using a fuel flowmeter), the designated representative shall include the following additional information in the monitoring plan:
 - (i) **Electronic.**
 - (A) Parameter monitored;
 - (B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;
 - (C) Test method used to check the accuracy of each fuel flowmeter;
 - (D) Submission status of the data;
 - (E) Monitoring system identification code; and
 - (F) The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable.
 - (ii) **Hardcopy.**
 - (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;
 - (B) For units using the optional default SO₂ emission rate for “pipeline natural gas” or “natural gas” in appendix D to this part, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to this part;
 - (C) For units using the 720 hour test under 2.3.6 of Appendix D of this part to determine the required sulfur sampling requirements, report the procedures and results of the test; and

- (D) For units using the 720 hour test under 2.3.5 of Appendix D of this part to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test;
- (2) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_x emission rate, the designated representative shall include in the monitoring plan:
 - (i) **Electronic.** Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit or gas-fired unit, as defined in § 72.2 of this chapter, and NO_x correlation test information, including:
 - (A) Test date;
 - (B) Test number;
 - (C) Operating level;
 - (D) Segment ID of the NO_x correlation curve;
 - (E) NO_x monitoring system identification;
 - (F) Low and high heat input rate values and corresponding NO_x emission rates;
 - (G) Type of fuel; and
 - (H) To document the unit qualifies as a peaking unit, current calendar year or ozone season, capacity factor data as specified in the definition of peaking unit in § 72.2 of this chapter, and an indication of whether the data are actual or projected data.
 - (ii) **Hardcopy.**
 - (A) A protocol containing methods used to perform the baseline or periodic NO_x emission test; and
 - (B) Unit operating parameters related to NO_x formation by the unit.
- (3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.
- (4) For each monitoring system recertification, maintenance, or other event, the designated representative shall include the following additional information in electronic format in the monitoring plan:
 - (i) Component/system identification code;
 - (ii) Event code or code for required test;
 - (iii) Event begin date and hour;
 - (iv) Conditionally valid data period begin date and hour (if applicable);
 - (v) Date and hour that last test is successfully completed; and
 - (vi) Indicator of whether conditionally valid data were reported at the end of the quarter.

- (5) For each unit using the low mass emission excepted methodology under § 75.19 the designated representative shall include the following additional information in the monitoring plan that accompanies the initial certification application:
 - (i) **Electronic.** For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under § 75.19(c). This report will include either the previous three years actual or projected emissions. The following items should be included:
 - (A) Current calendar year of application;
 - (B) Type of qualification;
 - (C) Years one, two, and three;
 - (D) Annual or ozone season measured, estimated or projected NO_x mass emissions for years one, two, and three;
 - (E) Annual measured, estimated or projected SO₂ mass emissions for years one, two, and three; and
 - (F) Annual or ozone season operating hours for years one, two, and three.
 - (ii) **Hardcopy.**
 - (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;
 - (B) For units which use the long term fuel flow methodology under § 75.19(c)(3), the designated representative must provide a diagram of the fuel flow to each affected unit or group of units and describe in detail the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;
 - (C) A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;
 - (D) A statement that the unit meets the applicability requirements in §§ 75.19(a) and (b); and
 - (E) Any unit historical actual, estimated and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under §§ 75.19(a) and 75.19(b).
- (6) For each gas-fired unit the designated representative shall include in the monitoring plan, in electronic format, the following: current calendar year, fuel usage data as specified in the definition of gas-fired in § 72.2 of this part, and an indication of whether the data are actual or projected data.
- (g) **Contents of the monitoring plan.** The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of this section may be implemented prior to January 1, 2009, as follows. In 2008, the owner or operator may opt to record and report the monitoring plan information in paragraphs (g) and (h) of this section, in lieu of recording and reporting the information in paragraphs (e) and (f) of this section. Each monitoring plan shall contain the information in paragraph (g)(1) of this section in electronic format and the

information in paragraph (g)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) **Electronic.**

- (i) The facility ORISPL number developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by EPA, if the facility does not have an ORISPL number). Also provide the following information for each unit and (as applicable) for each common stack and/or pipe, and each multiple stack and/or pipe involved in the monitoring plan:
 - (A) A representation of the exhaust configuration for the units in the monitoring plan. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) of the configuration. Provide the ID number of each unit and assign a unique ID number to each common stack, common pipe multiple stack and/or multiple pipe associated with the unit(s) represented in the monitoring plan. For common and multiple stacks and/or pipes, provide the activation date and deactivation date (if applicable) of each stack and/or pipe;
 - (B) Identification of the monitoring system location(s) (e.g., at the unit-level, on the common stack, at each multiple stack, etc.). Provide an indicator ("flag") if the monitoring location is at a bypass stack or in the ductwork (breeching);
 - (C) The stack exit height (ft) above ground level and ground level elevation above sea level, and the inside cross-sectional area (ft²) at the flue exit and at the flow monitoring location (for units with flow monitors, only). Also use appropriate codes to indicate the material(s) of construction and the shape(s) of the stack or duct cross-section(s) at the flue exit and (if applicable) at the flow monitor location. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the information in this paragraph (g)(1)(i)(C);
 - (D) The type(s) of fuel(s) fired by each unit. Indicate the start and (if applicable) end date of combustion for each type of fuel, and whether the fuel is the primary, secondary, emergency, or startup fuel;
 - (E) The type(s) of emission controls that are used to reduce SO₂, NO_x, and particulate emissions from each unit. Also provide the installation date, optimization date, and retirement date (if applicable) of the emission controls, and indicate whether the controls are an original installation;
 - (F) Maximum hourly heat input capacity of each unit. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for this parameter; and
 - (G) A non-load based unit indicator (if applicable) for units that do not produce electrical or thermal output.
- (ii) For each monitored parameter (e.g., SO₂, NO_x, flow, etc.) at each monitoring location, specify the monitoring methodology and the missing data approach for the parameter. If the unmonitored bypass stack approach is used for a particular parameter, indicate this by means of an appropriate code. Provide the activation date/hour, and deactivation date/hour (if applicable) for each monitoring methodology and each missing data approach.

- (iii) For each required continuous emission monitoring system, each fuel flowmeter system, and each continuous opacity monitoring system, identify and describe the major monitoring components in the monitoring system (e.g., gas analyzer, flow monitor, opacity monitor, moisture sensor, fuel flowmeter, DAHS software, etc.). Other important components in the system (e.g., sample probe, PLC, data logger, etc.) may also be represented in the monitoring plan, if necessary. Provide the following specific information about each component and monitoring system:
 - (A) For each required monitoring system:
 - (1) Assign a unique, 3-character alphanumeric identification code to the system;
 - (2) Indicate the parameter monitored by the system;
 - (3) Designate the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e); and
 - (4) Indicate the system activation date/hour and deactivation date/hour (as applicable).
 - (B) For each component of each monitoring system represented in the monitoring plan:
 - (1) Assign a unique, 3-character alphanumeric identification code to the component;
 - (2) Indicate the manufacturer, model and serial number;
 - (3) Designate the component type;
 - (4) For dual-span applications, indicate whether the analyzer component ID represents a high measurement scale, a low scale, or a dual range;
 - (5) For gas analyzers, indicate the moisture basis of measurement;
 - (6) Indicate the method of sample acquisition or operation, (e.g., extractive pollutant concentration monitor or thermal flow monitor); and
 - (7) Indicate the component activation date/hour and deactivation date/hour (as applicable).
- (iv) Explicit formulas, using the component and system identification codes for the primary monitoring system, and containing all constants and factors required to derive the required mass emissions, emission rates, heat input rates, etc. from the hourly data recorded by the monitoring systems. Formulas using the system and component ID codes for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). Provide the equation number or other appropriate code for each emissions formula (e.g., use code F-1 if Equation F-1 in appendix F to this part is used to calculate SO₂ mass emissions). Also identify each emissions formula with a unique three character alphanumeric code. The formula effective start date/hour and inactivation date/hour (as applicable) shall be included for each formula. The owner or operator of a unit for which the optional low mass emissions excepted methodology in § 75.19 is being used is not required to report such formulas.
- (v) For each parameter monitored with CEMS, provide the following information:
 - (A) Measurement scale (high or low);

- (B) Maximum potential value (and method of calculation). If NO_x emission rate in lb/mmBtu is monitored, calculate and provide the maximum potential NO_x emission rate in addition to the maximum potential NO_x concentration;
 - (C) Maximum expected value (if applicable) and method of calculation;
 - (D) Span value(s) and full-scale measurement range(s);
 - (E) Daily calibration units of measure;
 - (F) Effective date/hour, and (if applicable) inactivation date/hour of each span value. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the measurement scale and dual span information in paragraphs (g)(1)(v)(A), (g)(1)(v)(G), and (g)(1)(v)(H) of this section;
 - (G) An indication of whether dual spans are required. If two span values are required, then, on and after April 27, 2011, indicate whether an autoranging analyzer is used to represent the two measurement scales; and
 - (H) The default high range value (if applicable) and the maximum allowable low-range value for this option.
- (vi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter:
- (A) Identification of the parameter;
 - (B) Default, maximum, minimum, or constant value, and units of measure for the value;
 - (C) Purpose of the value;
 - (D) Indicator of use, i.e., during controlled hours, uncontrolled hours, or all operating hours;
 - (E) Type of fuel;
 - (F) Source of the value;
 - (G) Value effective date and hour;
 - (H) Date and hour that the value is no longer effective (if applicable);
 - (I) For units using the excepted methodology under § 75.19, the applicable SO₂ emission factor; and
 - (J) On and after April 27, 2011, group identification code.
- (vii) Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit or common stack on which hardware CEMS are installed:
- (A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr (i.e., klb/hr), rounded to the nearest klb/hr, or thermal output in mmBtu/hr, rounded to the nearest mmBtu/hr), for units that produce electrical or thermal output;
 - (B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);

- (C) Except for peaking units, identify the most frequently and second most frequently used load (or operating) levels (*i.e.*, low, mid, or high) in accordance with section 6.5.2.1 of appendix A to this part, expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);
 - (D) Except for peaking units, an indicator of whether the second most frequently used load (or operating) level is designated as normal in section 6.5.2.1 of appendix A to this part;
 - (E) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels (as applicable); and
 - (F) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, normal load (or operating) level(s) or two most frequently-used load (or operating) levels change and are updated.
- (viii) For each unit for which CEMS are not installed:
- (A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in klb/hr, rounded to the nearest klb/hr, or steam load in mmBtu/hr, rounded to the nearest mmBtu/hr);
 - (B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;
 - (C) Except for peaking units and units using the low mass emissions excepted methodology under § 75.19, identify the load level designated as normal, pursuant to section 6.5.2.1 of appendix A to this part, expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;
 - (D) The date of the load analysis used to determine the normal load level (as applicable); and
 - (E) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, or normal load level change and are updated.
- (ix) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:
- (A) Stack or duct width at the test location, ft;
 - (B) Stack or duct depth at the test location, ft;
 - (C) Wall effects adjustment factor (WAF), to the nearest 0.0001;
 - (D) Method of determining the WAF;
 - (E) WAF Effective date and hour;
 - (F) WAF no longer effective date and hour (if applicable);
 - (G) WAF determination date;
 - (H) Number of WAF test runs;
 - (I) Number of Method 1 traverse points in the WAF test;
 - (J) Number of test ports in the WAF test; and

(K) Number of Method 1 traverse points in the reference flow RATA.

(2) **Hardcopy.**

- (i) Information, including (as applicable): Identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_x emission rate, and span; and apportionment strategies under §§ 75.10 through 75.18.
- (ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of this section and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.
- (iii) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.
- (iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitoring systems and components, and stacks corresponding to the identification numbers provided in paragraphs (g)(1)(i) and (g)(1)(iii) of this section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.
- (v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.

(h) **Contents of monitoring plan for specific situations.** The following additional information shall be included in the monitoring plan for the specific situations described:

- (1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO₂ mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_x emission rate (using a fuel flowmeter), the designated representative shall include the following additional information for each fuel flowmeter system in the monitoring plan:

(i) **Electronic.**

- (A) Parameter monitored;
- (B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (*i.e.*, upper range value or unit maximum) for each fuel flowmeter;
- (C) Test method used to check the accuracy of each fuel flowmeter;
- (D) Monitoring system identification code;
- (E) The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable; and

- (F) Activation date/hour and (if applicable) inactivation date/hour for the fuel flowmeter system;
- (ii) **Hardcopy.**
 - (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;
 - (B) For units using the optional default SO₂ emission rate for “pipeline natural gas” or “natural gas” in appendix D to this part, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to this part;
 - (C) For units using the 720 hour test under 2.3.6 of Appendix D of this part to determine the required sulfur sampling requirements, report the procedures and results of the test; and
 - (D) For units using the 720 hour test under 2.3.5 of Appendix D of this part to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.
- (2) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_x emission rate, the designated representative shall include in the monitoring plan:
 - (i) **Electronic.** Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit, as defined in § 72.2 of this chapter for the current calendar year or ozone season, including: capacity factor data for three calendar years (or ozone seasons) as specified in the definition of peaking unit in § 72.2 of this chapter; the method of qualification used; and an indication of whether the data are actual or projected data. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the peaking unit qualification information in this paragraph (h)(2)(i).
 - (ii) **Hardcopy.**
 - (A) A protocol containing methods used to perform the baseline or periodic NO_x emission test; and
 - (B) Unit operating parameters related to NO_x formation by the unit.
- (3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.
- (4) For each unit using the low mass emissions excepted methodology under § 75.19 the designated representative shall include the following additional information in the monitoring plan that accompanies the initial certification application:
 - (i) **Electronic.** For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under § 75.19(c). This report will include either the previous three years actual or projected emissions. The following items should be included:

- (A) Current calendar year of application;
 - (B) Type of qualification;
 - (C) Years one, two, and three;
 - (D) Annual and/or ozone season measured, estimated or projected NO_x mass emissions for years one, two, and three;
 - (E) Annual measured, estimated or projected SO₂ mass emissions (if applicable) for years one, two, and three; and
 - (F) Annual or ozone season operating hours for years one, two, and three.
- (ii) **Hardcopy.**
- (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;
 - (B) For units which use the long term fuel flow methodology under § 75.19(c)(3), the designated representative must provide a diagram of the fuel flow to each affected unit or group of units and describe in detail the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;
 - (C) A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;
 - (D) A statement that the unit meets the applicability requirements in § 75.19(a) and (b); and
 - (E) Any unit historical actual, estimated and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under § 75.19(a) and 75.19(b).
- (5) For qualification as a gas-fired unit, as defined in § 72.2 of this part, the designated representative shall include in the monitoring plan, in electronic format, the following: current calendar year, fuel usage data for three calendar years (or ozone seasons) as specified in the definition of gas-fired in § 72.2 of this chapter, the method of qualification used, and an indication of whether the data are actual or projected data. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the gas-fired unit qualification information in this paragraph (h)(5).
- (6) For each monitoring location with a stack flow monitor that is exempt from performing 3-load flow RATAs (peaking units, bypass stacks, or by petition) the designated representative shall include in the monitoring plan an indicator of exemption from 3-load flow RATA using the appropriate exemption code.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26532, 26568, May 17, 1995; 61 FR 59161, Nov. 20, 1996; 64 FR 28605, May 26, 1999; 67 FR 40440, June 12, 2002; 70 FR 28682, May 18, 2005; 73 FR 4350, Jan. 24, 2008; 76 FR 17312, Mar. 28, 2011]

§§ 75.54-75.56 [Reserved]

§ 75.57 General recordkeeping provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

- (a) **Recordkeeping requirements for affected sources.** The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase “for each affected unit” also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§ 75.16 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:
- (1) The data and information required in paragraphs (b) through (h) of this section, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);
 - (2) The supporting data and information used to calculate values required in paragraphs (b) through (g) of this section, excluding the subhourly data points used to compute hourly averages under § 75.10(d), beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);
 - (3) The data and information required in § 75.58 for specific situations, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);
 - (4) The certification test data and information required in § 75.59 for tests required under § 75.20, beginning with the date of the first certification test performed, the quality assurance and quality control data and information required in § 75.59 for tests, and the quality assurance/quality control plan required under § 75.21 and appendix B to this part, beginning with the date of provisional certification;
 - (5) The current monitoring plan as specified in § 75.53, beginning with the initial submission required by § 75.62;
 - (6) The quality control plan as described in section 1 of appendix B to this part, beginning with the date of provisional certification; and
 - (7) The information required by sections 6.1.2(b) and (c) of appendix A to this part.
- (b) **Operating parameter record provisions.** The owner or operator shall record for each hour the following information on unit operating time, heat input rate, and load, separately for each affected unit and also for each group of units utilizing a common stack and a common monitoring system or utilizing a common pipe header and common fuel flowmeter:
- (1) Date and hour;
 - (2) Unit 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));
 - (3) Hourly gross unit load (rounded to nearest MWge) (or steam load in 1000 lb/hr at stated temperature and pressure, rounded to the nearest 1000 lb/hr, or mmBtu/hr of thermal output, rounded to the nearest mmBtu/hr, if elected in the monitoring plan);
 - (4) Operating load range corresponding to hourly gross load of 1 to 10, except for units using a common stack or common pipe header, which may use up to 20 load ranges for stack or fuel flow, as specified in the monitoring plan;
 - (5) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);

- (6) Identification code for formula used for heat input, as provided in § 75.53; and
- (7) For CEMS units only, F-factor for heat input calculation and indication of whether the diluent cap was used for heat input calculations for the hour.

(c) **SO₂ emission record provisions.** The owner or operator shall record for each hour the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except as provided under § 75.11(e) or for a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part or for a low mass emissions unit for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) for estimating SO₂ mass emissions:

- (1) For SO₂ concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:
 - (i) Component-system identification code, as provided in § 75.53;
 - (ii) Date and hour;
 - (iii) Hourly average SO₂ concentration (ppm, rounded to the nearest tenth);
 - (iv) Hourly average SO₂ concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d);
 - (v) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32; and
 - (vi) Method of determination for hourly average SO₂ concentration using Codes 1-55 in Table 4a of this section.
- (2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:
 - (i) Component-system identification code, as provided in § 75.53;
 - (ii) Date and hour;
 - (iii) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand);
 - (iv) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in § 75.24(d);
 - (v) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to § 75.32; and
 - (vi) Method of determination for hourly average flow rate using Codes 1-55 in Table 4a of this section.
- (3) For flue gas moisture content during unit operation (where SO₂ concentration is measured on a dry basis), as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:
 - (i) Component-system identification code, as provided in § 75.53;
 - (ii) Date and hour;

- (iii) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O₂, rounded to the nearest tenth);
 - (iv) Percent monitor data availability (recorded to the nearest tenth of a percent) for the moisture monitoring system, calculated pursuant to § 75.32; and
 - (v) Method of determination for hourly average moisture percentage, using Codes 1-55 in Table 4a of this section.
- (4) For SO₂ mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination:
- (i) Date and hour;
 - (ii) Hourly SO₂ mass emission rate (lb/hr, rounded to the nearest tenth);
 - (iii) Hourly SO₂ mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in § 75.24(d); and
 - (iv) Identification code for emissions formula used to derive hourly SO₂ mass emission rate from SO₂ concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of this section, as provided in § 75.53.

TABLE 4A—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified backup emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference method: SO ₂ : Method 6C. Flow: Method 2 or its allowable alternatives under appendix A to part 60 of this chapter. NO _x : Method 7E. CO ₂ or O ₂ : Method 3A.
5	For units with add-on SO ₂ and/or NO _x emission controls: SO ₂ concentration or NO _x emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO ₂ concentrations, CO ₂ concentrations, O ₂ concentrations, NO _x concentrations, flow rates, moisture percentages or NO _x emission rates for the hour before and the hour following a missing data period.
7	Initial missing data procedures used. Either: (a) the average of the hourly SO ₂ concentration, CO ₂ concentration, O ₂ concentration, or moisture percentage for the hour before and the hour following a missing data period; or (b) the arithmetic average of all NO _x concentration, NO _x emission rate, or flow rate values at the corresponding load range (or a higher load range), or at the corresponding operational bin (non-load-based units, only); or (c) the

Code	Hourly emissions/flow measurement or estimation method
	arithmetic average of all previous NO _x concentration, NO _x emission rate, or flow rate values (non-load-based units, only).
8	90th percentile hourly SO ₂ concentration, CO ₂ concentration, NO _x concentration, flow rate, moisture percentage, or NO _x emission rate or 10th percentile hourly O ₂ concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
9	95th percentile hourly SO ₂ concentration, CO ₂ concentration, NO _x concentration, flow rate, moisture percentage, or NO _x emission rate or 5th percentile hourly O ₂ concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
10	Maximum hourly SO ₂ concentration, CO ₂ concentration, NO _x concentration, flow rate, moisture percentage, or NO _x emission rate or minimum hourly O ₂ concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
11	Average of hourly flow rates, NO _x concentrations or NO _x emission rates in corresponding load range, for the applicable lookback period. For non-load-based units, report either the average flow rate, NO _x concentration or NO _x emission rate in the applicable lookback period, or the average flow rate or NO _x value at the corresponding operational bin (if operational bins are used).
12	Maximum potential concentration of SO ₂ , maximum potential concentration of CO ₂ , maximum potential concentration of NO _x maximum potential flow rate, maximum potential NO _x emission rate, maximum potential moisture percentage, minimum potential O ₂ concentration or minimum potential moisture percentage, as determined using § 72.2 of this chapter and section 2.1 of appendix A to this part (moisture missing data algorithm depends on which equations are used for emissions and heat input).
13	Maximum expected concentration of SO ₂ , maximum expected concentration of NO _x , or maximum controlled NO _x emission rate. (See § 75.34(a)(5)).
14	Diluent cap value (if the cap is replacing a CO ₂ measurement, use 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O ₂ measurement, use 14.0 percent for boilers and 19.0 percent for turbines).
15	1.25 times the maximum hourly controlled SO ₂ concentration, NO _x concentration at the corresponding load or operational bin, or NO _x emission rate at the corresponding load or operational bin, in the applicable lookback period (See § 75.34(a)(5)).
16	SO ₂ concentration value of 2.0 ppm during hours when only "very low sulfur fuel", as defined in § 72.2 of this chapter, is combusted.
17	Like-kind replacement non-redundant backup analyzer.
19	200 percent of the MPC; default high range value.
20	200 percent of the full-scale range setting (full-scale exceedance of high range).
21	Negative hourly CO ₂ concentration, SO ₂ concentration, NO _x concentration, percent moisture, or NO _x emission rate replaced with zero.
22	Hourly average SO ₂ or NO _x concentration, measured by a certified monitor at the control device inlet (units with add-on emission controls only).
23	Maximum potential SO ₂ concentration, NO _x concentration, CO ₂ concentration, or NO _x

Code	Hourly emissions/flow measurement or estimation method
	emission rate, or minimum potential O ₂ concentration or moisture percentage, for an hour in which flue gases are discharged through an unmonitored bypass stack.
24	Maximum expected NO _x concentration, or maximum controlled NO _x emission rate for an hour in which flue gases are discharged downstream of the NO _x emission controls through an unmonitored bypass stack, and the add-on NO _x emission controls are confirmed to be operating properly.
25	Maximum potential NO _x emission rate (MER). (Use only when a NO _x concentration full-scale exceedance occurs and the diluent monitor is unavailable.)
26	1.0 mmBtu/hr substituted for Heat Input Rate for an operating hour in which the calculated Heat Input Rate is zero or negative.
40	Fuel specific default value (or prorated default value) used for the hour.
53	Other quality-assured data approved through petition. These are treated as available hours for percent monitor availability calculations and are included in missing data lookback.
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.
55	Other substitute data approved through petition. These hours are not included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.

(d) **NO_x emission record provisions.** The owner or operator shall record the applicable information required by this paragraph for each affected unit for each hour or partial hour during which the unit operates, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part or a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating NO_x emission rate. For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under § 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

- (1) Component-system identification code, as provided in § 75.53 (including identification code for the moisture monitoring system, if applicable);
- (2) Date and hour;
- (3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in § 75.24(d);
- (4) Hourly average diluent gas concentration (for NO_x-diluent monitoring systems, only, in units of percent O₂ or percent CO₂, rounded to the nearest tenth);

- (5) If applicable, the hourly average moisture content of the stack gas (percent H₂O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O₂, rounded to the nearest tenth);
 - (6) Hourly average NO_x emission rate (for NO_x-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth);
 - (7) Hourly average NO_x emission rate (for NO_x-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;
 - (8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x-diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to § 75.32;
 - (9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average moisture percentage, using Codes 1-55 in Table 4a of this section; and
 - (10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in § 75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates.
- (e) **CO₂ emission record provisions.** Except for a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating CO₂ mass emissions, the owner or operator shall record or calculate CO₂ emissions for each affected unit using one of the following methods specified in this section:
- (1) If the owner or operator chooses to use a CO₂ CEMS (including an O₂ monitor and flow monitor, as specified in appendix F to this part), then the owner or operator shall record for each hour or partial hour during which the unit operates the following information for CO₂ mass emissions, as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:
 - (i) Component-system identification code, as provided in § 75.53 (including identification code for the moisture monitoring system, if applicable);
 - (ii) Date and hour;
 - (iii) Hourly average CO₂ concentration (in percent, rounded to the nearest tenth);
 - (iv) Hourly average volumetric flow rate (scfh, rounded to the nearest thousand scfh);
 - (v) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where CO₂ concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O₂, rounded to the nearest tenth);
 - (vi) Hourly average CO₂ mass emission rate (tons/hr, rounded to the nearest tenth);

- (vii) Percent monitor data availability for both the CO₂ monitoring system and, if applicable, the moisture monitoring system (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32;
 - (viii) Method of determination for hourly average CO₂ mass emission rate and hourly average CO₂ concentration, and, if applicable, for the hourly average moisture percentage, using Codes 1-55 in Table 4a of this section;
 - (ix) Identification code for emissions formula used to derive hourly average CO₂ mass emission rate, as provided in § 75.53; and
 - (x) Indication of whether the diluent cap was used for CO₂ calculation for the hour.
- (2) As an alternative to paragraph (e)(1) of this section, the owner or operator may use the procedures in § 75.13 and in appendix G to this part, and shall record daily the following information for CO₂ mass emissions:
- (i) Date;
 - (ii) Daily combustion-formed CO₂ mass emissions (tons/day, rounded to the nearest tenth);
 - (iii) For coal-fired units, flag indicating whether optional procedure to adjust combustion-formed CO₂ mass emissions for carbon retained in flyash has been used and, if so, the adjustment;
 - (iv) For a unit with a wet flue gas desulfurization system or other controls generating CO₂, daily sorbent-related CO₂ mass emissions (tons/day, rounded to the nearest tenth); and
 - (v) For a unit with a wet flue gas desulfurization system or other controls generating CO₂, total daily CO₂ mass emissions (tons/day, rounded to the nearest tenth) as the sum of combustion-formed emissions and sorbent-related emissions.
- (f) **Opacity records.** The owner or operator shall record opacity data as specified by the State or local air pollution control agency. If the State or local air pollution control agency does not specify recordkeeping requirements for opacity, then record the information required by paragraphs (f) (1) through (5) of this section for each affected unit, except as provided in §§ 75.14(b), (c), and (d). The owner or operator shall also keep records of all incidents of opacity monitor downtime during unit operation, including reason(s) for the monitor outage(s) and any corrective action(s) taken for opacity, as measured and reported by the continuous opacity monitoring system:
- (1) Component/system identification code;
 - (2) Date, hour, and minute;
 - (3) Average opacity of emissions for each six minute averaging period (in percent opacity);
 - (4) If the average opacity of emissions exceeds the applicable standard, then a code indicating such an exceedance has occurred; and
 - (5) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated according to the requirements of the procedure recommended for State Implementation Plans in appendix M to part 51 of this chapter.

- (g) ***Diluent record provisions.*** The owner or operator of a unit using a flow monitor and an O₂ diluent monitor to determine heat input, in accordance with Equation F-17 or F-18 of appendix F to this part, or a unit that accounts for heat input using a flow monitor and a CO₂ diluent monitor (which is used only for heat input determination and is not used as a CO₂ pollutant concentration monitor) shall keep the following records for the O₂ or CO₂ diluent monitor:
- (1) Component-system identification code, as provided in § 75.53;
 - (2) Date and hour;
 - (3) Hourly average diluent gas (O₂ or CO₂) concentration (in percent, rounded to the nearest tenth);
 - (4) Percent monitor data availability for the diluent monitor (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32; and
 - (5) Method of determination code for diluent gas (O₂ or CO₂) concentration data using Codes 1-55, in Table 4a of this section.
- (h) ***Missing data records.*** The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to correct such causes.

[64 FR 28609, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40440, June 12, 2002; 70 FR 28682, May 18, 2005; 72 FR 51528, Sept. 7, 2007; 73 FR 4353, Jan. 24, 2008; 76 FR 17313, Mar. 28, 2011]

§ 75.58 General recordkeeping provisions for specific situations.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

- (a) [Reserved]
- (b) ***Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.*** In accordance with § 75.34, the owner or operator of an affected unit with add-on emission controls shall either record the applicable information in paragraph (b)(3) of this section for each hour of missing SO₂ concentration data or NO_x emission rate (in addition to other information), or shall record the information in paragraph (b)(1) of this section for SO₂ or paragraph (b)(2) of this section for NO_x through an automated data acquisition and handling system, as appropriate to the type of add-on emission controls:
- (1) For units with add-on SO₂ emission controls using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing SO₂ concentration or volumetric flow data:
 - (i) The information required in § 75.57(c) for SO₂ concentration and volumetric flow, if either one of these monitors is still operating;
 - (ii) Date and hour;
 - (iii) Number of operating scrubber modules;
 - (iv) Total feedrate of slurry to each operating scrubber module (gal/min);
 - (v) Pressure differential across each operating scrubber module (inches of water column);
 - (vi) For a unit with a wet flue gas desulfurization system, an in-line measure of absorber pH for each operating scrubber module;

- (vii) For a unit with a dry flue gas desulfurization system, the inlet and outlet temperatures across each operating scrubber module;
 - (viii) For a unit with a wet flue gas desulfurization system, the percent solids in slurry for each scrubber module;
 - (ix) For a unit with a dry flue gas desulfurization system, the slurry feed rate (gal/min) to the atomizer nozzle;
 - (x) For a unit with SO₂ add-on emission controls other than wet or dry limestone, corresponding parameters approved by the Administrator;
 - (xi) Method of determination of SO₂ concentration and volumetric flow using Codes 1-55 in Table 4a of § 75.57; and
 - (xii) Inlet and outlet SO₂ concentration values, recorded by an SO₂ continuous emission monitoring system, and the removal efficiency of the add-on emission controls.
- (2) For units with add-on NO_x emission controls using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing NO_x emission rate data:
- (i) Date and hour;
 - (ii) Inlet air flow rate (scfh, rounded to the nearest thousand);
 - (iii) Excess O₂ concentration of flue gas at stack outlet (percent, rounded to the nearest tenth of a percent);
 - (iv) Carbon monoxide concentration of flue gas at stack outlet (ppm, rounded to the nearest tenth);
 - (v) Temperature of flue gas at furnace exit or economizer outlet duct (°F);
 - (vi) Other parameters specific to NO_x emission controls (e.g., average hourly reagent feedrate);
 - (vii) Method of determination of NO_x emission rate using Codes 1-55 in Table 4a of § 75.57; and
 - (viii) Inlet and outlet NO_x emission rate values recorded by a NO_x continuous emission monitoring system and the removal efficiency of the add-on emission controls.
- (3) Except as otherwise provided in § 75.34(d), for units with add-on SO₂ or NO_x emission controls following the provisions of §§ 75.34(a)(1), (a)(2), (a)(3) or (a)(5), the owner or operator shall record:
- (i) Parametric data which demonstrate, for each hour of missing SO₂ or NO_x emission data, the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data shall be maintained on site and shall be submitted, upon request, to the Administrator, EPA Regional office, State, or local agency;
 - (ii) A flag indicating, for each hour of missing SO₂ or NO_x emission data, either that the add-on emission controls are operating properly, as evidenced by all parameters being within the ranges specified in the quality assurance/quality control program, or that the add-on emission controls are not operating properly.
- (c) ***Specific SO₂ emission record provisions for gas-fired or oil-fired units using optional protocol in appendix D to this part.*** In lieu of recording the information in § 75.57(c), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part for estimating SO₂ mass emissions:

- (1) For each hour when the unit is combusting oil:
 - (i) Date and hour;
 - (ii) Hourly average volumetric flow rate of oil, while the unit combusts oil, with the units in which oil flow is recorded (gal/hr, scf/hr, m³/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);
 - (iii) Sulfur content of oil sample used to determine SO₂ mass emission rate (rounded to nearest hundredth for diesel fuel or to the nearest tenth of a percent for other fuel oil) (flag value if derived from missing data procedures);
 - (iv) [Reserved];
 - (v) Mass flow rate of oil combusted each hour and method of determination (lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);
 - (vi) SO₂ mass emission rate from oil (lb/hr, rounded to the nearest tenth);
 - (vii) For units using volumetric oil flowmeters, density of oil with the units in which oil density is recorded and method of determination (flag value if derived from missing data procedures);
 - (viii) Gross calorific value of oil used to determine heat input and method of determination (Btu/lb) (flag value if derived from missing data procedures);
 - (ix) Hourly heat input rate from oil, according to procedures in appendix D to this part (mmBtu/hr, to the nearest tenth);
 - (x) Fuel usage time for combustion of oil during the hour (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)) (flag to indicate multiple/single fuel types combusted);
 - (xi) Monitoring system identification code;
 - (xii) Operating load range corresponding to gross unit load (01-20);
 - (xiii) Type of oil combusted; and
 - (xiv) Heat input formula ID and SO₂ Formula ID (required beginning January 1, 2009).
- (2) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part for daily manual oil sampling, when the unit is combusting oil, the highest sulfur content recorded from the most recent 30 daily oil samples (rounded to the nearest tenth of a percent).
- (3) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part, when either an assumed oil sulfur content or density value is used, or when as-delivered oil sampling is performed:
 - (i) Record the measured sulfur content, gross calorific value, and, if applicable, density from each fuel sample; and
 - (ii) Record and report the assumed sulfur content, gross calorific value, and, if applicable, density used to calculate SO₂ mass emission rate or heat input rate.
- (4) For each hour when the unit is combusting gaseous fuel:
 - (i) Date and hour.

- (ii) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (mmBtu/hr, rounded to the nearest tenth).
 - (iii) Sulfur content or SO₂ emission rate, in one of the following formats, in accordance with the appropriate procedure from appendix D to this part:
 - (A) Sulfur content of gas sample and method of determination (rounded to the nearest 0.1 grains/100 scf) (flag value if derived from missing data procedures); or
 - (B) Default SO₂ emission rate of 0.0006 lb/mmBtu for pipeline natural gas, or calculated SO₂ emission rate for natural gas from section 2.3.2.1.1 of appendix D to this part.
 - (iv) Hourly flow rate of gaseous fuel, while the unit combusts gas (100 scfh) and source of data code for gas flow rate.
 - (v) Gross calorific value of gaseous fuel used to determine heat input rate (Btu/100 scf) (flag value if derived from missing data procedures).
 - (vi) SO₂ mass emission rate due to the combustion of gaseous fuels (lb/hr).
 - (vii) Fuel usage time for combustion of gaseous fuel during the hour (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)) (flag to indicate multiple/single fuel types combusted).
 - (viii) Monitoring system identification code.
 - (ix) Operating load range corresponding to gross unit load (01-20).
 - (x) Type of gas combusted; and
 - (xi) Heat input formula ID and SO₂ Formula ID (required beginning January 1, 2009).
- (5) For each oil sample or sample of diesel fuel:
- (i) Date of sampling;
 - (ii) Sulfur content (percent, rounded to either the nearest hundredth, or nearest ten-thousandth for diesel fuels and to the nearest tenth for other fuel oil);
 - (iii) Gross calorific value (Btu/lb); and
 - (iv) Density or specific gravity, if required to convert volume to mass.
- (6) For each sample of gaseous fuel for sulfur content:
- (i) Date of sampling; and
 - (ii) Sulfur content (grains/100 scf, rounded to the nearest tenth).
- (7) For each sample of gaseous fuel for gross calorific value:
- (i) Date of sampling; and
 - (ii) Gross calorific value (Btu/100 scf).
- (8) For each oil sample or sample of gaseous fuel:
- (i) Type of oil or gas; and

- (ii) Type of sulfur sampling (using codes in tables D-4 and D-5 of appendix D to this part) and value used in calculations, and type of GCV or density sampling (using codes in tables D-4 and D-5 of appendix D to this part).

(d) ***Specific NO_x emission record provisions for gas-fired peaking units or oil-fired peaking units using optional protocol in appendix E to this part.*** In lieu of recording the information in § 75.57(d), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part for estimating NO_x emission rate. The owner or operator shall meet the requirements of this section, except that the requirements under paragraphs (d)(1)(vii) and (d)(2)(vii) of this section shall become applicable on the date on which the owner or operator is required to monitor, record, and report NO_x mass emissions under an applicable State or federal NO_x mass emission reduction program, if the provisions of subpart H of this part are adopted as requirements under such a program.

(1) For each hour when the unit is combusting oil:

- (i) Date and hour;
- (ii) Hourly average mass flow rate of oil while the unit combusts oil with the units in which oil flow is recorded (lb/hr);
- (iii) Gross calorific value of oil used to determine heat input (Btu/lb);
- (iv) Hourly average NO_x emission rate from combustion of oil (lb/mmBtu, rounded to the nearest hundredth);
- (v) Heat input rate of oil (mmBtu/hr, rounded to the nearest tenth);
- (vi) Fuel usage time for combustion of oil during the hour (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);
- (vii) NO_x mass emissions, calculated in accordance with section 8.1 of appendix F to this part;
- (viii) NO_x monitoring system identification code;
- (ix) Fuel flow monitoring system identification code;
- (x) Segment identification of the correlation curve; and
- (xi) Heat input rate formula ID (required beginning January 1, 2009).

(2) For each hour when the unit is combusting gaseous fuel:

- (i) Date and hour;
- (ii) Hourly average fuel flow rate of gaseous fuel, while the unit combusts gas (100 scfh);
- (iii) Gross calorific value of gaseous fuel used to determine heat input (Btu/100 scf) (flag value if derived from missing data procedures);
- (iv) Hourly average NO_x emission rate from combustion of gaseous fuel (lb/mmBtu, rounded to nearest hundredth);
- (v) Heat input rate from gaseous fuel, while the unit combusts gas (mmBtu/hr, rounded to the nearest tenth);

- (vi) Fuel usage time for combustion of gaseous fuel during the hour (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);
 - (vii) NO_x mass emissions, calculated in accordance with section 8.1 of appendix F to this part;
 - (viii) NO_x monitoring system identification code;
 - (ix) Fuel flow monitoring system identification code;
 - (x) Segment identification of the correlation curve; and
 - (xi) Heat input rate formula ID (required beginning January 1, 2009).
- (3) For each hour when the unit combusts multiple fuels:
- (i) Date and hour;
 - (ii) Hourly average heat input rate from all fuels (mmBtu/hr, rounded to the nearest tenth); and
 - (iii) Hourly average NO_x emission rate for the unit for all fuels (lb/mmBtu, rounded to the nearest hundredth).
- (4) For each hour when the unit combusts any fuel(s):
- (i) For stationary gas turbines and diesel or dual-fuel reciprocating engines, hourly averages of operating parameters under section 2.3 of appendix E to this part (flag if value is outside of manufacturer's recommended range); and
 - (ii) For boilers, hourly average boiler O₂ reading (percent, rounded to the nearest tenth) (flag if value exceeds by more than 2 percentage points the O₂ level recorded at the same heat input during the previous NO_x emission rate test); and
 - (iii) On and after April 27, 2011, operating condition codes for the following:
 - (A) Unit operated on emergency fuel;
 - (B) Correlation curve for the fuel mixture has expired;
 - (C) Operating parameter is outside of normal limits;
 - (D) Uncontrolled hour;
 - (E) Operation above highest tested heat input rate point on the curve;
 - (F) Operating parameter data missing or invalid;
 - (G) Designated operational and control equipment parameters within normal limits; and
 - (H) Operation below lowest tested heat input rate point on the curve.
- (5) For each fuel sample:
- (i) Date of sampling;
 - (ii) Gross calorific value (Btu/lb for oil, Btu/100 scf for gaseous fuel); and
 - (iii) Density or specific gravity, if required to convert volume to mass.
- (6) Flag to indicate multiple or single fuels combusted.

(e) *Specific SO₂ emission record provisions during the combustion of gaseous fuel.*

- (1) If SO₂ emissions are determined in accordance with the provisions in § 75.11(e)(2) during hours in which only gaseous fuel is combusted in a unit with an SO₂ CEMS, the owner or operator shall record the information in paragraph (c)(3) of this section in lieu of the information in §§ 75.57(c)(1), (c)(3), and (c)(4), for those hours.
- (2) The provisions of this paragraph apply to a unit which, in accordance with the provisions of § 75.11(e)(3), uses an SO₂ CEMS to determine SO₂ emissions during hours in which only gaseous fuel is combusted in the unit. If the unit sometimes burns only gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) as a primary and/or backup fuel and at other times combusts higher sulfur fuels, such as coal or oil, as primary and/or backup fuel(s), then the owner or operator shall keep records on-site, in a form suitable for inspection, of the type(s) of fuel(s) burned during each period of missing SO₂ data and the number of hours that each type of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns very low sulfur fuel exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.

(f) *Specific SO₂, NO_x, and CO₂ record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.* In lieu of recording the information in §§ 75.57(b) through (e), the owner or operator shall record the following information for each affected low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c):

- (1) All low mass emission units shall report for each hour:
 - (i) Date and hour;
 - (ii) Unit operating time (units using the long term fuel flow methodology report operating time to be 1);
 - (iii) Fuel type (pipeline natural gas, natural gas, other gaseous fuel, residual oil, or diesel fuel). If more than one type of fuel is combusted in the hour, either:
 - (A) Indicate the fuel type which results in the highest emission factors for NO_x (this option is in effect through December 31, 2008); or
 - (B) Indicate the fuel type resulting in the highest emission factor for each parameter (SO₂, NO_x emission rate, and CO₂) separately (this option is required on and after January 1, 2009);
 - (iv) Average hourly NO_x emission rate (lb/mmBtu, rounded to the nearest thousandth);
 - (v) Hourly NO_x mass emissions (lbs, rounded to the nearest tenth);
 - (vi) Hourly SO₂ mass emissions (lbs, rounded to the nearest tenth);
 - (vii) Hourly CO₂ mass emissions (tons, rounded to the nearest tenth);
 - (viii) Hourly calculated unit heat input in mmBtu;
 - (ix) Hourly unit output in gross load or steam load;
 - (x) The method of determining hourly heat input: unit maximum rated heat input, unit long term fuel flow or group long term fuel flow;

- (xi) The method of determining NO_x emission rate used for the hour: default based on fuel combusted, unit specific default based on testing or historical data, group default based on representative testing of identical units, unit specific based on testing of a unit with NO_x controls operating, or missing data value;
 - (xii) Control status of the unit; and
 - (xiii) Base or peak load indicator (as applicable); and
 - (xiv) Multiple fuel flag.
- (2) Low mass emission units using the optional long term fuel flow methodology to determine unit heat input shall report for each quarter:
- (i) Type of fuel;
 - (ii) Beginning date and hour of long term fuel flow measurement period;
 - (iii) End date and hour of long term fuel flow period;
 - (iv) Quantity of fuel measured;
 - (v) Units of measure;
 - (vi) Fuel GCV value used to calculate heat input;
 - (vii) Units of GCV;
 - (viii) Method of determining fuel GCV used;
 - (ix) Method of determining fuel flow over period;
 - (x) Monitoring-system identification code;
 - (xi) Quarter and year;
 - (xii) Total heat input (mmBtu); and
 - (xiii) Operating hours in period.

[64 FR 28612, May 26, 1999, as amended at 67 FR 40441, 40442, June 12, 2002; 70 FR 28683, May 18, 2005; 73 FR 4354, Jan. 24, 2008; 76 FR 17314, Mar. 28, 2011]

§ 75.59 Certification, quality assurance, and quality control record provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

- (a) **Continuous emission or opacity monitoring systems.** The owner or operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup monitors) measuring and recording emissions or flow from an affected unit.
 - (1) For each SO₂ or NO_x pollutant concentration monitor, flow monitor, CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions), or diluent gas monitor (including wet- and dry-basis O₂ monitors used to determine percent moisture), the owner or operator shall record the following for all daily and 7-day calibration error tests, and all off-line calibration demonstrations, including any follow-up tests after corrective action:

- (i) Component-system identification code (on and after January 1, 2009, only the component identification code is required);
 - (ii) Instrument span and span scale;
 - (iii) On and after April 27, 2011, date, hour, and minute;
 - (iv) Reference value (*i.e.*, calibration gas concentration or reference signal value, in ppm or other appropriate units);
 - (v) Observed value (monitor response during calibration, in ppm or other appropriate units);
 - (vi) Percent calibration error (rounded to the nearest tenth of a percent) (flag if using alternative performance specification for low emitters or differential pressure flow monitors);
 - (vii) Reference signal or calibration gas level;
 - (viii) For 7-day calibration error tests, a test number and reason for test;
 - (ix) For 7-day calibration tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gas, as defined in § 72.2 of this chapter and appendix A to this part, was used to conduct calibration error testing;
 - (x) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test; and
 - (xi) Indication of whether the unit is off-line or on-line.
- (2) For each flow monitor, the owner or operator shall record the following for all daily interference checks, including any follow-up tests after corrective action.
- (i) Component-system identification code (after January 1, 2009, only the component identification code is required);
 - (ii) Date and hour;
 - (iii) Code indicating whether monitor passes or fails the interference check; and
 - (iv) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test.
- (3) For each SO₂ or NO_x pollutant concentration monitor, CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions), or diluent gas monitor (including wet- and dry-basis O₂ monitors used to determine percent moisture), the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action.
- (i) Component-system identification code (on and after January 1, 2009, only the component identification code is required);
 - (ii) Instrument span and span scale (only span scale is required on and after January 1, 2009);
 - (iii) Calibration gas level;
 - (iv) Date and time (hour and minute) of each gas injection at each calibration gas level;
 - (v) Reference value (*i.e.*, reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units);

- (vi) Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units);
 - (vii) Mean of reference values and mean of measured values at each calibration gas level;
 - (viii) Linearity error at each of the reference gas concentrations (rounded to nearest tenth of a percent) (flag if using alternative performance specification);
 - (ix) Test number and reason for test (flag if aborted test); and
 - (x) Description of any adjustments, corrective action, or maintenance prior to a passed test or following a failed test.
- (4) For each differential pressure type flow monitor, the owner or operator shall record items in paragraphs (a)(4) (i) through (v) of this section, for all quarterly leak checks, including any follow-up tests after corrective action. For each flow monitor, the owner or operator shall record items in paragraphs (a)(4) (vi) and (vii) for all flow-to-load ratio and gross heat rate tests:
- (i) Component-system identification code (on and after January 1, 2009, only the system identification code is required).
 - (ii) Date and hour.
 - (iii) Reason for test.
 - (iv) Code indicating whether monitor passes or fails the quarterly leak check.
 - (v) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test.
 - (vi) Test data from the flow-to-load ratio or gross heat rate (GHR) evaluation, including:
 - (A) Monitoring system identification code;
 - (B) Calendar year and quarter;
 - (C) Indication of whether the test is a flow-to-load ratio or gross heat rate evaluation;
 - (D) Indication of whether bias adjusted flow rates were used;
 - (E) Average absolute percent difference between reference ratio (or GHR) and hourly ratios (or GHR values);
 - (F) Test result;
 - (G) Number of hours used in final quarterly average;
 - (H) Number of hours exempted for use of a different fuel type;
 - (I) Number of hours exempted for load ramping up or down;
 - (J) Number of hours exempted for scrubber bypass;
 - (K) Number of hours exempted for hours preceding a normal-load flow RATA;
 - (L) Number of hours exempted for hours preceding a successful diagnostic test, following a documented monitor repair or major component replacement;

- (M) Number of hours excluded for flue gases discharging simultaneously thorough a main stack and a bypass stack; and
 - (N) Test number.
- (vii) Reference data for the flow-to-load ratio or gross heat rate evaluation, including (as applicable):
 - (A) Reference flow RATA end date and time;
 - (B) Test number of the reference RATA;
 - (C) Reference RATA load and load level;
 - (D) Average reference method flow rate during reference flow RATA;
 - (E) Reference flow/load ratio;
 - (F) Average reference method diluent gas concentration during flow RATA and diluent gas units of measure;
 - (G) Fuel specific F_d -or F_c -factor during flow RATA and F-factor units of measure;
 - (H) Reference gross heat rate value;
 - (I) Monitoring system identification code;
 - (J) Average hourly heat input rate during RATA;
 - (K) Average gross unit load;
 - (L) Operating load level; and
 - (M) An indicator ("flag") if separate reference ratios are calculated for each multiple stack.
- (5) For each SO₂ pollutant concentration monitor, flow monitor, each CO₂ emissions concentration monitor (including any O₂ concentration monitor used to determine CO₂ mass emissions or heat input), each NO_x-diluent continuous emission monitoring system, each NO_x concentration monitoring system, each diluent gas (O₂ or CO₂) monitor used to determine heat input, each moisture monitoring system, and each approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy test audits:
 - (i) Reference method(s) used.
 - (ii) Individual test run data from the relative accuracy test audit for the SO₂ concentration monitor, flow monitor, CO₂ emissions concentration monitor, NO_x-diluent continuous emission monitoring system, diluent gas (O₂ or CO₂) monitor used to determine heat input, NO_x concentration monitoring system, moisture monitoring system, or approved alternative monitoring system, including:
 - (A) Date, hour, and minute of beginning of test run;
 - (B) Date, hour, and minute of end of test run;
 - (C) Monitoring system identification code;
 - (D) Test number and reason for test;

- (E) Operating level (low, mid, high, or normal, as appropriate) and number of operating levels comprising test;
 - (F) Normal load (or operating level) indicator for flow RATAs (except for peaking units);
 - (G) Units of measure;
 - (H) Run number;
 - (I) Run value from CEMS being tested, in the appropriate units of measure;
 - (J) Run value from reference method, in the appropriate units of measure;
 - (K) Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion;
 - (L) Average gross unit load, expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest thousand lb/hr; on and after April 27, 2011, for units that do not produce electrical or thermal output, record, instead, the average stack gas velocity at the operating level being tested; and
 - (M) Flag to indicate whether an alternative performance specification has been used.
- (iii) Calculations and tabulated results, as follows:
- (A) Arithmetic mean of the monitoring system measurement values, of the reference method values, and of their differences, as specified in Equation A-7 in appendix A to this part;
 - (B) Standard deviation, as specified in Equation A-8 in appendix A to this part;
 - (C) Confidence coefficient, as specified in Equation A-9 in appendix A to this part;
 - (D) Statistical "t" value used in calculations;
 - (E) Relative accuracy test results, as specified in Equation A-10 in appendix A to this part. For multi-level flow monitor tests the relative accuracy test results shall be recorded at each load (or operating) level tested. Each load (or operating) level shall be expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest thousand lb/hr, or as otherwise specified by the Administrator, for units that do not produce electrical or thermal output;
 - (F) Bias test results as specified in section 7.6.4 of appendix A to this part;
 - (G) Bias adjustment factor from Equation A-12 in appendix A to this part for any monitoring system that failed the bias test (except as otherwise provided in section 7.6.5 of appendix A to this part) and 1.000 for any monitoring system that passed the bias test; and
 - (H) On and after April 27, 2011, RATA frequency code.
- (iv) Description of any adjustment, corrective action, or maintenance prior to a passed test or following a failed or aborted test.
- (v) F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O₂ or CO₂) concentration measurements into NO_x emission rates (in lb/mmBtu), heat input or CO₂ emissions.

- (vi) For flow monitors, the equation used to linearize the flow monitor and the numerical values of the polynomial coefficients or K factor(s) of that equation.
 - (vii) For moisture monitoring systems, the coefficient or “K” factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method.
- (6) For each SO₂, NO_x, or CO₂ pollutant concentration monitor, each component of a NO_x-diluent continuous emission monitoring system, and each CO₂ or O₂ monitor used to determine heat input, the owner or operator shall record the following information for the cycle time test:
- (i) Component-system identification code (on and after January 1, 2009, only the component identification code is required);
 - (ii) Date;
 - (iii) Start and end times;
 - (iv) Upscale and downscale cycle times for each component;
 - (v) Stable start monitor value;
 - (vi) Stable end monitor value;
 - (vii) Reference value of calibration gas(es);
 - (viii) Calibration gas level;
 - (ix) Total cycle time;
 - (x) Reason for test; and
 - (xi) Test number.
- (7) In addition to the information in paragraph (a)(5) of this section, the owner or operator shall record, for each relative accuracy test audit, supporting information sufficient to substantiate compliance with all applicable sections and appendices in this part. Unless otherwise specified in this part or in an applicable test method, the information in paragraphs (a)(7)(i) through (a)(7)(vi) of this section may be recorded either in hard copy format, electronic format or a combination of the two, and the owner or operator shall maintain this information in a format suitable for inspection and audit purposes. This RATA supporting information shall include, but shall not be limited to, the following data elements:
- (i) For each RATA using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate:
 - (A) Information indicating whether or not the location meets requirements of Method 1 in appendix A to part 60 of this chapter; and
 - (B) Information indicating whether or not the equipment passed the required leak checks.
 - (ii) For each run of each RATA using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):
 - (A) Operating level (low, mid, high, or normal, as appropriate);
 - (B) Number of reference method traverse points;

- (C) Average stack gas temperature (°F);
 - (D) Barometric pressure at test port (inches of mercury);
 - (E) Stack static pressure (inches of H₂O);
 - (F) Absolute stack gas pressure (inches of mercury);
 - (G) Percent CO₂ and O₂ in the stack gas, dry basis;
 - (H) CO₂ and O₂ reference method used;
 - (I) Moisture content of stack gas (percent H₂O);
 - (J) Molecular weight of stack gas, dry basis (lb/lb-mole);
 - (K) Molecular weight of stack gas, wet basis (lb/lb-mole);
 - (L) Stack diameter (or equivalent diameter) at the test port (ft);
 - (M) Average square root of velocity head of stack gas (inches of H₂O) for the run;
 - (N) Stack or duct cross-sectional area at test port (ft²);
 - (O) Average velocity (ft/sec);
 - (P) Average stack flow rate, adjusted, if applicable, for wall effects (scfh, wet basis);
 - (Q) Flow rate reference method used;
 - (R) Average velocity, adjusted for wall effects;
 - (S) Calculated (site-specific) wall effects adjustment factor determined during the run, and, if different, the wall effects adjustment factor used in the calculations; and
 - (T) Default wall effects adjustment factor used.
- (iii) For each traverse point of each run of each RATA using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):
- (A) Reference method probe type;
 - (B) Pressure measurement device type;
 - (C) Traverse point ID;
 - (D) Probe or pitot tube calibration coefficient;
 - (E) Date of latest probe or pitot tube calibration;
 - (F) Average velocity differential pressure at traverse point (inches of H₂O) or the average of the square roots of the velocity differential pressures at the traverse point ((inches of H₂O)^{1/2});
 - (G) T_S, stack temperature at the traverse point (°F);
 - (H) Composite (wall effects) traverse point identifier;
 - (I) Number of points included in composite traverse point;

- (J) Yaw angle of flow at traverse point (degrees);
- (K) Pitch angle of flow at traverse point (degrees);
- (L) Calculated velocity at traverse point both accounting and not accounting for wall effects (ft/sec); and
- (M) Probe identification number.
- (iv) For each RATA using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO₂, NO_x, CO₂, or O₂ concentration:
 - (A) Pollutant or diluent gas being measured;
 - (B) Span of reference method analyzer;
 - (C) Type of reference method system (e.g., extractive or dilution type);
 - (D) Reference method dilution factor (dilution type systems, only);
 - (E) Reference gas concentrations (zero, mid, and high gas levels) used for the 3-point pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point pre-test system calibration error test) and for any subsequent recalibrations;
 - (F) Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s);
 - (G) Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value);
 - (H) Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or (for dilution type reference method systems) for each pre-run or post-run system calibration error check;
 - (I) Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check;
 - (J) The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks;
 - (K) The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre- and post-run system bias (or system calibration error) checks;
 - (L) The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value);
 - (M) The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value);
 - (N) Calibration drift and zero drift of analyzer during each RATA run (percentage of span value);
 - (O) Moisture basis of the reference method analysis;

- (P) Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested);
 - (Q) Unadjusted (raw) average pollutant or diluent gas concentration for each run;
 - (R) Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture;
 - (S) The F-factor used to convert reference method data to units of lb/mmBtu (if applicable);
 - (T) Date(s) of the latest analyzer interference test(s);
 - (U) Results of the latest analyzer interference test(s);
 - (V) Date of the latest NO₂ to NO conversion test (Method 7E only);
 - (W) Results of the latest NO₂ to NO conversion test (Method 7E only); and
 - (X) For each calibration gas cylinder used during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and certified gas concentration(s).
- (v) For each test run of each moisture determination using Method 4 in appendix A to part 60 of this chapter (or its allowable alternatives), whether the determination is made to support a gas RATA, to support a flow RATA, or to quality assure the data from a continuous moisture monitoring system, record the following data elements (as applicable to the moisture measurement method used):
- (A) Test number;
 - (B) Run number;
 - (C) The beginning date, hour, and minute of the run;
 - (D) The ending date, hour, and minute of the run;
 - (E) Unit operating level (low, mid, high, or normal, as appropriate);
 - (F) Moisture measurement method;
 - (G) Volume of H₂O collected in the impingers (ml);
 - (H) Mass of H₂O collected in the silica gel (g);
 - (I) Dry gas meter calibration factor;
 - (J) Average dry gas meter temperature (°F);
 - (K) Barometric pressure (inches of mercury);
 - (L) Differential pressure across the orifice meter (inches of H₂O);
 - (M) Initial and final dry gas meter readings (ft³);
 - (N) Total sample gas volume, corrected to standard conditions (dscf); and
 - (O) Percentage of moisture in the stack gas (percent H₂O).
- (vi) The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 of appendix A to this part.

- (vii) [Reserved]
- (viii) [Reserved]
- (ix) For a unit with a flow monitor installed on a rectangular stack or duct, if a site-specific default or measured wall effects adjustment factor (WAF) is used to correct the stack gas volumetric flow rate data to account for velocity decay near the stack or duct wall, the owner or operator shall keep records of the following for each flow RATA performed with EPA Method 2 in appendices A-1 and A-2 to part 60 of this chapter, subsequent to the WAF determination:
 - (A) Monitoring system ID;
 - (B) Test number;
 - (C) Operating level;
 - (D) RATA end date and time;
 - (E) Number of Method 1 traverse points; and
 - (F) Wall effects adjustment factor (WAF), to the nearest 0.0001.
- (8) For each certified continuous emission monitoring system, continuous opacity monitoring system, excepted monitoring system, or alternative monitoring system, the date and description of each event which requires certification, recertification, or certain diagnostic testing of the system and the date and type of each test performed. If the conditional data validation procedures of § 75.20(b)(3) are to be used to validate and report data prior to the completion of the required certification, recertification, or diagnostic testing, the date and hour of the probationary calibration error test shall be reported to mark the beginning of conditional data validation.
- (9) When hardcopy relative accuracy test reports, certification reports, recertification reports, or semiannual or annual reports for gas or flow rate CEMS are required or requested under § 75.60(b)(6) or § 75.63, the reports shall include, at a minimum, the following elements (as applicable to the type(s) of test(s) performed):
 - (i) Summarized test results.
 - (ii) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time, and relative accuracy tests.
 - (iii) For pollutant concentration monitor or diluent monitor relative accuracy tests at normal operating load:
 - (A) The raw reference method data from each run, i.e., the data under paragraph (a)(7)(iv)(Q) of this section (usually in the form of a computerized printout, showing a series of one-minute readings and the run average);
 - (B) The raw data and results for all required pre-test, post-test, pre-run and post-run quality assurance checks (i.e., calibration gas injections) of the reference method analyzers, i.e., the data under paragraphs (a)(7)(iv)(E) through (a)(7)(iv)(N) of this section;
 - (C) The raw data and results for any moisture measurements made during the relative accuracy testing, i.e., the data under paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of this section; and

- (D) Tabulated, final, corrected reference method run data (i.e., the actual values used in the relative accuracy calculations), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced.
- (iv) For relative accuracy tests for flow monitors:
 - (A) The raw flow rate reference method data, from Reference Method 2 (or its allowable alternatives) under appendix A to part 60 of this chapter, including auxiliary moisture data (often in the form of handwritten data sheets), i.e., the data under paragraphs (a)(7)(ii)(A) through (a)(7)(ii)(T), paragraphs (a)(7)(iii)(A) through (a)(7)(iii)(M), and, if applicable, paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of this section; and
 - (B) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the flow rate reference method data and other necessary measurements, such as moisture, stack temperature and pressure), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced.
- (v) Calibration gas certificates for the gases used in the linearity, calibration error, and cycle time tests and for the calibration gases used to quality assure the gas monitor reference method data during the relative accuracy test audit.
- (vi) Laboratory calibrations of the source sampling equipment.
- (vii) A copy of the test protocol used for the CEMS certifications or recertifications, including narrative that explains any testing abnormalities, problematic sampling, and analytical conditions that required a change to the test protocol, and/or solutions to technical problems encountered during the testing program.
- (viii) Diagrams illustrating test locations and sample point locations (to verify that locations are consistent with information in the monitoring plan). Include a discussion of any special traversing or measurement scheme. The discussion shall also confirm that sample points satisfy applicable acceptance criteria.
- (ix) Names of key personnel involved in the test program, including test team members, plant contacts, agency representatives and test observers on site.
- (x) For testing involving use of EPA Protocol gases, the owner or operator shall record in electronic and hardcopy format the following information, as applicable:
 - (A) On and after September 26, 2011, for each gas monitor, for both low and high measurement ranges, record the following information for the mid-level or high-level EPA Protocol gas (as applicable) that is used for daily calibration error tests, and the low-, mid-, and high-level gases used for quarterly linearity checks. For O₂, if purified air is used as the high-level gas for daily calibrations or linearity checks, record the following information for the low- and mid-level EPA Protocol gas used for linearity checks, instead:
 - (1) Gas level code;
 - (2) A code for the type of EPA Protocol gas used;
 - (3) The PGVP vendor ID issued by EPA for the EPA Protocol gas production site that supplied the EPA Protocol gas cylinder;

- (4) The expiration date for the EPA Protocol gas cylinder; and
 - (5) The cylinder number.
- (B) On and after September 26, 2011, for each usage of Reference Method 3A in appendix A-2 to part 60 of this chapter, or Method 6C or 7E in appendix A-4 to part 60 of this chapter performed using EPA Protocol gas for the certification, recertification, routine quality assurance or diagnostic testing (reportable diagnostics, only) of a Part 75 monitoring system, record the information required by paragraphs (a)(9)(x)(A)(1) through (5) of this section.
- (xi) On and after March 27, 2012, for all RATAs performed pursuant to § 75.74(c)(2)(ii), section 6.5 of appendix A to this part and section 2.3.1 of appendix B to this part, and for all NO_x emission testing performed pursuant to section 2.1 of appendix E to this part, or § 75.19(c)(1)(iv), the owner or operator shall record the following information as provided by the AETB:
 - (A) The name, telephone number and e-mail address of the Air Emission Testing Body;
 - (B) The name of each on-site Qualified Individual, as defined in § 72.2 of this chapter;
 - (C) For the reference method(s) that were performed, the date(s) that each on-site Qualified Individual took and passed the relevant qualification exam(s) required by ASTM D7036-04 (incorporated by reference, see § 75.6); and
 - (D) The name and e-mail address of each qualification exam provider.
- (10) Whenever reference methods are used as backup monitoring systems pursuant to § 75.20(d)(3), the owner or operator shall record the following information:
 - (i) For each test run using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):
 - (A) Unit or stack identification number;
 - (B) Reference method system and component identification numbers;
 - (C) Run date and hour;
 - (D) The data in paragraph (a)(7)(ii) of this section, except for paragraphs (a)(7)(ii)(A), (F), (H), (L) and (Q) through (T); and
 - (E) The data in paragraph (a)(7)(iii), except on a run basis.
 - (ii) For each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO₂, NO_x, CO₂, or O₂ concentration:
 - (A) Unit or stack identification number;
 - (B) The reference method system and component identification numbers;
 - (C) Run number;
 - (D) Run start date and hour;
 - (E) Run end date and hour;
 - (F) The data in paragraphs (a)(7)(iv)(B) through (I) and (L) through (O); and

- (G) Stack gas density adjustment factor (if applicable).
- (iii) For each hour of each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO₂, NO_x, CO₂, or O₂ concentration:
 - (A) Unit or stack identification number;
 - (B) The reference method system and component identification numbers;
 - (C) Run number;
 - (D) Run date and hour;
 - (E) Pollutant or diluent gas being measured;
 - (F) Unadjusted (raw) average pollutant or diluent gas concentration for the hour; and
 - (G) Average pollutant or diluent gas concentration for the hour, adjusted as appropriate for moisture, calibration bias (or calibration error) and stack gas density.
- (11) For each other quality-assurance test or other quality assurance activity, the owner or operator shall record the following (as applicable):
 - (i) Component/system identification code;
 - (ii) Parameter;
 - (iii) Test or activity completion date and hour;
 - (iv) Test or activity description;
 - (v) Test result;
 - (vi) Reason for test; and
 - (vii) Test code.
- (12) For each request for a quality assurance test extension or exemption, for any loss of exempt status, and for each single-load flow RATA claim pursuant to section 2.3.1.3(c)(3) of appendix B to this part, the owner or operator shall record the following (as applicable):
 - (i) For a RATA deadline extension or exemption request:
 - (A) Monitoring system identification code;
 - (B) Date of last RATA;
 - (C) RATA expiration date without extension;
 - (D) RATA expiration date with extension;
 - (E) Type of RATA extension or exemption claimed or lost;
 - (F) Year to date hours of usage of fuel other than very low sulfur fuel;
 - (G) Year to date hours of non-redundant back-up CEMS usage at the unit/stack; and
 - (H) Quarter and year.
 - (ii) For a linearity test or flow-to-load ratio test quarterly exemption:

- (A) Component-system identification code;
 - (B) Type of test;
 - (C) Basis for exemption;
 - (D) Quarter and year; and
 - (E) Span scale.
- (iii) [Reserved]
- (iv) For a fuel flowmeter accuracy test extension:
 - (A) Component-system identification code;
 - (B) Date of last accuracy test;
 - (C) Accuracy test expiration date without extension;
 - (D) Accuracy test expiration date with extension;
 - (E) Type of extension;
 - (F) Quarter and year; and
 - (G) On and after April 27, 2011, fuel code for Ozone Season Only reporters under § 75.74(c).
- (v) For a single-load (or single-level) flow RATA claim:
 - (A) Monitoring system identification code;
 - (B) Ending date of last annual flow RATA;
 - (C) The relative frequency (percentage) of unit or stack operation at each load (or operating) level (low, mid, and high) since the previous annual flow RATA, to the nearest 0.1 percent;
 - (D) End date of the historical load (or operating level) data collection period; and
 - (E) Indication of the load (or operating) level (low, mid or high) claimed for the single-load flow RATA.
- (13) An indication that data have been excluded from a periodic span and range evaluation of an SO₂ or NO_x monitor under section 2.1.1.5 or 2.1.2.5 of appendix A to this part and the reason(s) for excluding the data. For purposes of reporting under § 75.64(a), this information shall be reported with the quarterly report as descriptive text consistent with § 75.64(g).
- (14) [Reserved]
- (15) On and after March 27, 2012, for all RATAs performed pursuant to § 75.74(c)(2)(ii), section 6.5 of appendix A to this part or section 2.3.1 of appendix B to this part, the owner or operator shall record in electronic format the following information as provided by the AETB:
 - (i) The name, telephone number and e-mail address of the Air Emission Testing Body;
 - (ii) The name of each on-site Qualified Individual, as defined in § 72.2 of this chapter;
 - (iii) For the reference method(s) that were performed, the date(s) that each on-site Qualified Individual took and passed the relevant qualification exam(s) required by ASTM D7036-04 (incorporated by reference, see § 75.6); and

(iv) The name and e-mail address of each qualification exam provider.

(b) **Excepted monitoring systems for gas-fired and oil-fired units.** The owner or operator shall record the applicable information in this section for each excepted monitoring system following the requirements of appendix D to this part or appendix E to this part for determining and recording emissions from an affected unit.

(1) For certification and quality assurance testing of fuel flowmeters tested against a reference fuel flow rate (i.e., flow rate from another fuel flowmeter under section 2.1.5.2 of appendix D to this part or flow rate from a procedure according to a standard incorporated by reference under section 2.1.5.1 of appendix D to this part):

- (i) Unit or common pipe header identification code;
- (ii) Component and system identification codes of the fuel flowmeter being tested (on and after January 1, 2009, only the component identification code is required);
- (iii) Date and hour of test completion, for a test performed in-line at the unit;
- (iv) Date and hour of flowmeter reinstallation, for laboratory tests;
- (v) Test number;
- (vi) Upper range value of the fuel flowmeter;
- (vii) Flowmeter measurements during accuracy test (and mean of values), including units of measure;
- (viii) Reference flow rates during accuracy test (and mean of values), including units of measure;
- (ix) Level of fuel flowrate test during runs (low, mid or high);
- (x) Average flowmeter accuracy for low and high fuel flowrates and highest flowmeter accuracy of any level designated as mid, expressed as a percent of upper range value;
- (xi) Indicator of whether test method was a lab comparison to reference meter or an in-line comparison against a master meter;
- (xii) Test result (aborted, pass, or fail); and
- (xiii) Description of fuel flowmeter calibration specification or procedure (in the certification application, or periodically if a different method is used for annual quality assurance testing).

(2) For each transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter used under section 2.1.6 of appendix D to this part:

- (i) Component and system identification codes of the fuel flowmeter being tested (on and after January 1, 2009, only the component identification code is required);
- (ii) Completion date and hour of test;
- (iii) For each transmitter or transducer: transmitter or transducer type (differential pressure, static pressure, or temperature); the full-scale value of the transmitter or transducer, transmitter input (pre-calibration) prior to accuracy test, including units of measure; and expected transmitter output during accuracy test (reference value from NIST-traceable equipment), including units of measure;

- (iv) For each transmitter or transducer tested: output during accuracy test, including units of measure; transmitter or transducer accuracy as a percent of the full-scale value; and transmitter output level as a percent of the full-scale value;
 - (v) Average flowmeter accuracy at low and high level fuel flowrates and highest flowmeter accuracy of any level designated as mid fuel flowrate, expressed as a percent of upper range value;
 - (vi) Test result (pass, fail, or aborted);
 - (vii) Test number; and
 - (viii) Accuracy determination methodology.
- (3) For each visual inspection of the primary element or transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter under sections 2.1.6.1 through 2.1.6.4 of appendix D to this part:
- (i) Date of inspection/test;
 - (ii) Hour of completion of inspection/test;
 - (iii) Component and system identification codes of the fuel flowmeter being inspected/tested; and
 - (iv) Results of inspection/test (pass or fail).
- (4) For fuel flowmeters that are tested using the optional fuel flow-to-load ratio procedures of section 2.1.7 of appendix D to this part:
- (i) Test data for the fuel flowmeter flow-to-load ratio or gross heat rate check, including:
 - (A) Component/system identification code (on and after January 1, 2009, only the monitoring system identification code is required);
 - (B) Calendar year and quarter;
 - (C) Indication of whether the test is for fuel flow-to-load ratio or gross heat rate;
 - (D) Quarterly average absolute percent difference between baseline for fuel flow-to-load ratio (or baseline gross heat rate and hourly quarterly fuel flow-to-load ratios (or gross heat rate value);
 - (E) Test result;
 - (F) Number of hours used in the analysis;
 - (G) Number of hours excluded due to co-firing;
 - (H) Number of hours excluded due to ramping;
 - (I) Number of hours excluded in lower 25.0 percent range of operation; and
 - (J) Test number.
 - (ii) Reference data for the fuel flowmeter flow-to-load ratio or gross heat rate evaluation, including:

- (A) Completion date and hour of most recent primary element inspection or test number of the most recent primary element inspection (as applicable); (on and after January 1, 2009, the test number of the most recent primary element inspection is required in lieu of the completion date and hour for the most recent primary element inspection);
 - (B) Completion date and hour of most recent flow meter of transmitter accuracy test or test number of the most recent flowmeter or transmitter accuracy test (as applicable); (on and after January 1, 2009, the test number of the most recent flowmeter or transmitter accuracy test is required in lieu of the completion date and hour for the most recent flowmeter or transmitter accuracy test);
 - (C) Beginning date and hour of baseline period;
 - (D) Completion date and hour of baseline period;
 - (E) Average fuel flow rate, in 100 scfh for gas and lb/hr for oil;
 - (F) Average load, in megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output;
 - (G) Baseline fuel flow-to-load ratio, in the appropriate units of measure (if using fuel flow-to-load ratio);
 - (H) Baseline gross heat rate if using gross heat rate, in the appropriate units of measure (if using gross heat rate check);
 - (I) Number of hours excluded from baseline data due to ramping;
 - (J) Number of hours excluded from baseline data in lower 25.0 percent of range of operation;
 - (K) Average hourly heat input rate;
 - (L) Flag indicating baseline data collection is in progress and that fewer than four calendar quarters have elapsed since the quarter of the last flowmeter QA test;
 - (M) Number of hours excluded due to co-firing; and
 - (N) Monitoring system identification code.
- (5) For gas-fired peaking units or oil-fired peaking units using the optional procedures of appendix E to this part, for each initial performance, periodic, or quality assurance/quality control-related test:
- (i) For each run of emission data, record the following data:
 - (A) Unit or common pipe identification code;
 - (B) Monitoring system identification code for appendix E system (on and after January 1, 2009, component identification codes shall be reported in addition to the monitoring system identification code);
 - (C) Run start date and time;
 - (D) Run end date and time;
 - (E) Total heat input during the run (mmBtu);
 - (F) NO_x emission rate (lb/mmBtu) from reference method;
 - (G) Response time of the O₂ and NO_x reference method analyzers;

- (H) Type of fuel(s) combusted during the run. This requirement remains in effect through December 31, 2008;
 - (I) Heat input rate (mmBtu/hr) during the run;
 - (J) Test number;
 - (K) Run number;
 - (L) Operating level during the run;
 - (M) NO_x concentration recorded by the reference method during the run;
 - (N) Diluent concentration recorded by the reference method during the run; and
 - (O) Moisture measurement for the run (if applicable).
- (ii) For each run during which oil or mixed fuels are combusted record the following data:
- (A) Unit or common pipe identification code;
 - (B) Monitoring system identification code for oil monitoring system (on and after January 1, 2009, component identification codes shall be reported in addition to the monitoring system identification code);
 - (C) Run start date and time;
 - (D) Run end date and time;
 - (E) Mass flow or volumetric flow of oil, in the units of measure for the type of fuel flowmeter;
 - (F) Gross calorific value of oil in the appropriate units of measure;
 - (G) Density of fuel oil in the appropriate units of measure (if density is used to convert oil volume to mass);
 - (H) Hourly heat input (mmBtu) during run from oil;
 - (I) Test number;
 - (J) Run number; and
 - (K) Operating level during the run.
- (iii) For each run during which gas or mixed fuels are combusted record the following data:
- (A) Unit or common pipe identification code;
 - (B) Monitoring system identification code for gas monitoring system (on and after January 1, 2009, component identification codes shall be reported in addition to the monitoring system identification code);
 - (C) Run start date and time;
 - (D) Run end date and time;
 - (E) Volumetric flow of gas (100 scf);
 - (F) Gross calorific value of gas (Btu/100 scf);

- (G) Hourly heat input (mmBtu) during run from gas;
 - (H) Test number;
 - (I) Run number; and
 - (J) Operating level during the run.
- (iv) For each operating level at which runs were performed:
 - (A) Completion date and time of last run for operating level (as applicable). This requirement remains in effect through December 31, 2008;
 - (B) Type of fuel(s) combusted during test;
 - (C) Average heat input rate at that operating level (mmBtu/hr);
 - (D) Arithmetic mean of NO_x emission rates from reference method run at this level;
 - (E) F-factor used in calculations of NO_x emission rate at that operating level;
 - (F) Unit operating parametric data related to NO_x formation for that unit type (e.g., excess O₂ level, water/fuel ratio);
 - (G) Test number;
 - (H) Operating level for runs; and
 - (I) Component identification code (required on and after January 1, 2009).
- (6) On and after March 27, 2012, for all stack testing performed pursuant to section 2.1 of appendix E to this part, the owner or operator shall record in electronic format the following information as provided by the AETB:
 - (i) The name, telephone number and e-mail address of the Air Emission Testing Body;
 - (ii) The name of each on-site Qualified Individual, as defined in § 72.2 of this chapter;
 - (iii) For the reference method(s) that were performed, the date(s) that each on-site Qualified Individual took and passed the relevant qualification exam(s) required by ASTM D7036-04 (incorporated by reference, see § 75.6); and
 - (iv) The name and e-mail address of each qualification exam provider.
- (c) Except as otherwise provided in § 75.58(b)(3)(i), for units with add-on SO₂ or NO_x emission controls following the provisions of § 75.34(a)(1) or (a)(2), the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 of appendix B to this part:
 - (1) A list of operating parameters for the add-on emission controls, including parameters in § 75.58(b), appropriate to the particular installation of add-on emission controls; and
 - (2) The range of each operating parameter in the list that indicates the add-on emission controls are properly operating.
- (d) **Exempted monitoring for low mass emissions units under § 75.19(c)(1)(iv).** For oil-and gas-fired units using the optional SO₂, NO_x and CO₂ emissions calculations for low mass emission units under § 75.19, the owner or operator shall record the following information for tests performed to determine a fuel and unit-specific default as provided in § 75.19(c)(1)(iv):

- (1) For each run of each test performed using the procedures of section 2.1 of appendix E to this part, record the following data:
 - (i) Unit or common pipe identification code;
 - (ii) Run start date and time;
 - (iii) Run end date and time;
 - (iv) NO_x emission rate (lb/mmBtu) from reference method;
 - (v) Response time of the O₂ and NO_x reference method analyzers;
 - (vi) Type of fuel(s) combusted during the run;
 - (vii) Test number;
 - (viii) Run number;
 - (ix) Operating level during the run;
 - (x) NO_x concentration recorded by the reference method during the run;
 - (xi) Diluent concentration recorded by the reference method during the run;
 - (xii) Moisture measurement for the run (if applicable); and
 - (xiii) An indicator ("flag") if the run is used to calculate the highest 3-run average NO_x emission rate at any load level.
- (2) For each single-load or multiple-load appendix E test, record the following:
 - (i) The three-run average NO_x emission rate for each load level;
 - (ii) An indicator that the average NO_x emission rate is the highest NO_x average emission rate recorded at any load level of the test (if appropriate);
 - (iii) The default NO_x emission rate (highest three-run average NO_x emission rate at any load level);
 - (iv) An indicator that the add-on NO_x emission controls were operating or not operating during each run of the test;
 - (v) Parameter data indicating the use and efficacy of control equipment during the test; and
 - (vi) Indicator of whether the testing was done at base load, peak load or both (if appropriate); and
 - (vii) The default NO_x emission rate for peak load hours (if applicable).
- (3) For each unit in a group of identical units qualifying for reduced testing under § 75.19(c)(1)(iv)(B), record the following data:
 - (i) The unique group identification code assigned to the group. This code must include the ORIS code of one of the units in the group;
 - (ii) The ORIS code or facility identification code for the unit;
 - (iii) The plant name of the facility at which the unit is located, consistent with the facility's monitoring plan;
 - (iv) The identification code for the unit, consistent with the facility's monitoring plan;

- (v) A record of whether or not the unit underwent fuel and unit-specific testing for purposes of establishing a fuel and unit-specific NO_x emission rate for purposes of § 75.19;
 - (vi) The completion date of the fuel and unit-specific test performed for purposes of establishing a fuel and unit-specific NO_x emission rate for purposes of § 75.19;
 - (vii) The fuel and unit-specific NO_x default rate established for the group of identical units under § 75.19;
 - (viii) The type of fuel combusted for the units during testing and represented by the resulting default NO_x emission rate;
 - (ix) The control status for the units during testing and represented by the resulting default NO_x emission rate;
 - (x) Documentation supporting the qualification of all units in the group for reduced testing, in accordance with the criteria established in § 75.19(c)(1)(iv)(B)(1);
 - (xi) Purpose of group tests;
 - (xii) On and after April 27, 2011, the number of tests for group; and
 - (xiii) On and after April 27, 2011, the number of units in group.
- (4) On and after March 27, 2012, for all NO_x emission testing performed pursuant to § 75.19(c)(1)(iv), the owner or operator shall record in electronic format the following information as provided by the AETB:
- (i) The name, telephone number and e-mail address of the Air Emission Testing Body;
 - (ii) The name of each on-site Qualified Individual, as defined in § 72.2 of this chapter;
 - (iii) For the reference method(s) that were performed, the date(s) that each on-site Qualified Individual took and passed the relevant qualification exam(s) required by ASTM D7036-04 (incorporated by reference, see § 75.6); and
 - (iv) The name and e-mail address of each qualification exam provider.
- (e) **DAHS Verification.** For each DAHS (missing data and formula) verification that is required for initial certification, recertification, or for certain diagnostic testing of a monitoring system, record the date and hour that the DAHS verification is successfully completed. (This requirement only applies to units that report monitoring plan data in accordance with § 75.53(g) and (h).)

[64 FR 28614, May 26, 1999, as amended at 67 FR 40442, June 12, 2002; 70 FR 28683, May 18, 2005; 63 FR 4354, Jan. 24, 2008; 76 FR 17315, Mar. 28, 2011]

Subpart G—Reporting Requirements

§ 75.60 General provisions.

- (a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of § 72.21 of this chapter for all submissions.
- (b) **Submissions.** The designated representative shall submit all reports and petitions (except as provided in § 75.61) as follows:

- (1) **Initial certifications.** The designated representative shall submit initial certification applications according to § 75.63.
 - (2) **Recertifications.** The designated representative shall submit recertification applications according to § 75.63.
 - (3) **Monitoring plans.** The designated representative shall submit monitoring plans according to § 75.62.
 - (4) **Electronic quarterly reports.** The designated representative shall submit electronic quarterly reports according to § 75.64.
 - (5) **Other petitions and communications.** The designated representative shall submit petitions, correspondence, application forms, designated representative signature, and petition-related test results in hardcopy to the Administrator. Additional petition requirements are specified in §§ 75.66 and 75.67.
 - (6) **Semiannual or annual RATA reports.** If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy RATA report within 45 days after completing a required semiannual or annual RATA according to section 2.3.1 of appendix B to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(a)(9) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.
 - (7) **Routine appendix E retest reports.** If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.
- (c) **Confidentiality of data.** The following provisions shall govern the confidentiality of information submitted under this part.
- (1) All emission data reported in quarterly reports under § 75.64 shall remain public information.
 - (2) For information submitted under this part other than emission data submitted in quarterly reports, the designated representative must assert a claim of confidentiality at the time of submission for any information he or she wishes to have treated as confidential business information (CBI) under subpart B of part 2 of this chapter. Failure to assert a claim of confidentiality at the time of submission may result in disclosure of the information by EPA without further notice to the designated representative.
 - (3) Any claim of confidentiality for information submitted in quarterly reports under § 75.64 must include substantiation of the claim. Failure to provide substantiation may result in disclosure of the information by EPA without further notice.
 - (4) As provided under subpart B of part 2 of this chapter, EPA may review information submitted to determine whether it is entitled to confidential treatment even when confidentiality claims are initially received. The EPA will contact the designated representative as part of such a review process.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26538, May 17, 1995; 64 FR 28620, May 26, 1999; 67 FR 40442, June 12, 2002; 73 FR 4356, Jan. 24, 2008; 76 FR 17316, Mar. 28, 2011]

§ 75.61 Notifications.

- (a) **Submission.** The designated representative for an affected unit (or owner or operator, as specified) shall submit notice to the Administrator, to the appropriate EPA Regional Office, and to the applicable State and local air pollution control agencies for the following purposes, as required by this part.
- (1) **Initial certification and recertification test notifications.** The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in § 75.20 for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section. The owner or operator shall also provide written notification of testing performed under § 75.19(c)(1)(iv)(A) to establish fuel-and-unit-specific NO_x emission rates for low mass emissions units. Such notifications are not required, however, for initial certifications and recertifications of excepted monitoring systems under appendix D to this part.
- (i) Notification of initial certification testing and full recertification. Initial certification test notifications and notifications of full recertification testing under § 75.20(b)(2) shall be submitted not later than 21 days prior to the first scheduled day of certification or recertification testing. In emergency situations when full recertification testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.
- (ii) **Notification of certification retesting, and partial recertification testing.** For retesting required following a loss of certification under § 75.20(a)(5) or for partial recertification testing required under § 75.20(b)(2), notice of the date of any required RATA testing or any required retesting under section 2.3 in appendix E to this part shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing; except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.
- (iii) **Repeat of testing without notice.** Notwithstanding the above notice requirements, the owner or operator may elect to repeat a certification or recertification test immediately, without advance notification, whenever the owner or operator has determined during the certification or recertification testing that a test was failed or must be aborted, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.
- (iv) **Waiver from notification requirements.** The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may issue a waiver from the notification requirement of paragraph (a)(1)(ii) of this section, for a unit or a group of units, for

one or more recertification tests or other retests. The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may also discontinue the waiver and reinstate the notification requirement of paragraph (a)(1)(ii) of this section for future recertification tests (or other retests) of a unit or a group of units.

- (2) ***New unit, newly affected unit, new stack, or new flue gas desulfurization system operation notification.*** The designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation, or becomes affected, or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere.
- (i) Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation or becomes affected, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.
- (ii) If the date when the unit commences commercial operation or becomes affected, or the date when the new stack or flue gas desulfurization system exhausts emissions to the atmosphere, whichever is applicable, changes from the planned date, a notification of the actual date shall be submitted not later than 7 days following: The date the unit commences commercial operation or becomes affected, or the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.
- (3) ***Unit shutdown and commencement of commercial operation.*** For an affected unit that will be shut down on the relevant compliance date specified in § 75.4 or in a State or Federal pollutant mass emissions reduction program that adopts the monitoring and reporting requirements of this part, if the owner or operator is relying on the provisions in § 75.4(d) to postpone certification testing, the designated representative for the unit shall submit notification of unit shutdown and commencement of commercial operation as follows:
- (i) For planned unit shutdowns (e.g., extended maintenance outages), written notification of the planned shutdown date shall be provided at least 21 days prior to the applicable compliance date, and written notification of the planned date of commencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual shutdown date or the actual date of commencement of commercial operation differs from the planned date, written notice of the actual date shall be submitted no later than 7 days following the actual date of shutdown or of commencement of commercial operation, as applicable;
- (ii) For unplanned unit shutdowns (e.g., forced outages), written notification of the actual shutdown date shall be provided no more than 7 days after the shutdown, and written notification of the planned date of commencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual date of commencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of commencement of commercial operation.
- (4) ***Use of backup fuels for appendix E procedures.*** The designated representative for an affected oil-fired or gas-fired peaking unit that is using an excepted monitoring system under appendix E of this part and that is relying on the provisions in § 75.4(f) to postpone testing of a fuel shall submit written notification of that fact no later than 45 days prior to the deadline in § 75.4. The designated representative shall also submit a notification that such a fuel has been combusted no later than 7

days after the first date of combustion of any fuel for which testing has not been performed under appendix E after the deadline in § 75.4. Such notice shall also include notice that testing under appendix E either was performed during the initial combustion or notice of the date that testing will be performed.

- (5) **Periodic relative accuracy test audits, appendix E retests, and low mass emissions unit retests.** The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, of periodic retesting performed under section 2.2 of appendix E to this part, and of periodic retesting of low mass emissions units performed under § 75.19(c)(1)(iv)(D), no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the respective State agency or office of EPA, and the notice is provided as soon as practicable after the new testing date is known, but no later than twenty-four (24) hours in advance of the new date of testing.
- (i) Written notification under paragraph (a) (5) of this section may be provided either by mail or by facsimile. In addition, written notification may be provided by electronic mail, provided that the respective State agency or office of EPA agrees that this is an acceptable form of notification.
- (ii) Notwithstanding the notice requirements under paragraph (a)(5) of this section, the owner or operator may elect to repeat a periodic relative accuracy test, appendix E retest, or low mass emissions unit retest immediately, without additional notification whenever the owner or operator has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.
- (iii) **Waiver from notification requirements.** The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may issue a waiver from the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for a unit or a group of units for one or more tests. The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may also discontinue the waiver and reinstate the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for future tests for a unit or a group of units. In addition, if an observer from a State agency or EPA is present when a test is rescheduled, the observer may waive all notification requirements under paragraph (a)(5) of this section for the rescheduled test.
- (6) **Notice of combustion of emergency fuel under appendix D or E.** The designated representative of an oil-fired unit or gas-fired unit using appendix D or E of this part shall, for each calendar quarter in which emergency fuel is combusted, provide notice of the combustion of the emergency fuel in the cover letter (or electronic equivalent) which transmits the next quarterly report submitted under § 75.64. The notice shall specify the exact dates and hours during which the emergency fuel was combusted.
- (7) **Long-term cold storage and recommencement of commercial operation.** The designated representative for an affected unit that is placed into long-term cold storage that is relying on the provisions in § 75.4(d) or § 75.64(a), either to postpone certification testing or to discontinue the submittal of quarterly reports during the period of long-term cold storage, shall provide written notification of long-term cold storage status and recommencement of commercial operation as follows:

(i) Whenever an affected unit has been placed into long-term cold storage, written notification of the date and hour that the unit was shutdown and a statement from the designated representative stating that the shutdown is expected to last for at least two years from that date, in accordance with the definition for long-term cold storage of a unit as provided in § 72.2 of this chapter.

(ii) Whenever an affected unit that has been placed into long-term cold storage is expected to resume operation, written notification shall be submitted 45 calendar days prior to the planned date of recommencement of commercial operation. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

(8) **Certification deadline date for new or newly affected units.** The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in § 75.4(b) or § 75.4(c), or as specified in a State or Federal SO₂ or NO_x mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, or H of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached.

(b) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems as specified in § 75.20(c)(8) to the State or local air pollution control agency.

(c) If the Administrator determines that notification substantially similar to that required in this section is required by any other State or local agency, the owner or operator or designated representative may send the Administrator a copy of that notification to satisfy the requirements of this section, provided the ORISPL unit identification number(s) is denoted.

[60 FR 26538, May 17, 1995, as amended at 61 FR 25582, May 22, 1996; 61 FR 59162, Nov. 22, 1996; 64 FR 28620, May 26, 1999; 67 FR 40442, 40443, June 12, 2002; 73 FR 4356, Jan. 24, 2008; 76 FR 17316, Mar. 28, 2011]

§ 75.62 Monitoring plan submittals.

(a) **Submission** —

(1) **Electronic.** Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator as follows: no later than 21 days prior to the initial certification tests; at the time of each certification or recertification application submission; and (prior to or concurrent with) the submittal of the electronic quarterly report for a reporting quarter where an update of the electronic monitoring plan information is required, either under § 75.53(b) or elsewhere in this part.

(2) **Hardcopy.** The designated representative shall submit all of the hardcopy information required under § 75.53 to the appropriate EPA Regional Office and the appropriate State and/or local air pollution control agency prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy

monitoring plan change is associated with the certification or recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

- (b) **Contents.** Monitoring plans shall contain the information specified in § 75.53 of this part.
- (c) **Format.** The designated representative shall submit each monitoring plan in a format specified by the Administrator.
- (d) On and after April 27, 2011, consistent with § 72.21 of this chapter, a hardcopy cover letter signed by the Designated Representative (DR) shall accompany each hardcopy monitoring plan submittal. The cover letter shall include the certification statement described in § 72.21(b) of this chapter, and shall be submitted to the applicable EPA Regional Office and to the appropriate State or local air pollution control agency. For electronic monitoring plan submittals to the Administrator, a cover letter is not required. However, at his or her discretion, the DR may include important explanatory text or comments with an electronic monitoring plan submittal, so long as the information is provided in an electronic format that is compatible with the other data required to be reported under this section.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26539, May 17, 1995; 64 FR 28621, May 26, 1999; 67 FR 40443, June 12, 2002; 73 FR 4356, Jan. 24, 2008; 76 FR 17316, Mar. 28, 2011]

§ 75.63 Initial certification or recertification application.

- (a) **Submission.** The designated representative for an affected unit or a combustion source shall submit applications and reports as follows:
 - (1) **Initial certifications.**
 - (i) For CEM systems or excepted monitoring systems under appendix D or E to this part, within 45 days after completing all initial certification tests, submit:
 - (A) To the Administrator, the electronic information required by paragraph (b)(1) of this section. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.
 - (B) To the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency, the hardcopy information required by paragraph (b)(2) of this section.
 - (ii) For units for which the owner or operator is applying for certification approval of the optional excepted methodology under § 75.19 for low mass emissions units, submit, no later than 45 days prior to commencing use of the methodology:
 - (A) To the Administrator, the electronic low mass emission qualification information required by § 75.53(f)(5)(i) or § 75.53(h)(4)(i) (as applicable) and paragraph (b)(1)(i) of this section; and
 - (B) To the applicable EPA Regional Office and appropriate State and/or local air pollution control agency, the hardcopy information required by § 75.19(a)(2) and § 75.53(f)(5)(ii) or § 75.53(h)(4)(ii) (as applicable), the hardcopy results of any appendix E (of this part) tests or any CEMS data analysis used to derive a fuel-and-unit-specific default NO_x emission rate.

(2) **Recertifications and diagnostic testing.**

- (i) Within 45 days after completing all recertification tests under § 75.20(b), submit to the Administrator the electronic information required by paragraph (b)(1) of this section. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.
- (ii) Within 45 days after completing all recertification tests under § 75.20(b), submit the hardcopy information required by paragraph (b)(2) of this section to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement to provide hardcopy recertification test and data results. The applicable EPA Regional Office or the appropriate State or local air pollution control agency may also discontinue the waiver and reinstate the requirement of this paragraph to provide a hardcopy report of the recertification test data and results.
- (iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (see § 75.20(b)) are required rather than recertification testing, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted prior to or concurrent with the electronic quarterly report required under § 75.64. Notwithstanding the requirement of § 75.59(e), for DAHS (missing data and formula) verifications, no hardcopy submittal is required; the owner or operator shall keep these test results on-site in a format suitable for inspection.

(b) **Contents.** Each application for initial certification or recertification shall contain the following information, as applicable:

(1) **Electronic.**

- (i) A complete, up-to-date version of the electronic portion of the monitoring plan, according to § 75.53(e) and (f), in the format specified in § 75.62(c).
- (ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.59, and the results of any failed tests that affect data validation.

(2) **Hardcopy.**

- (i) Any changed portions of the hardcopy monitoring plan information required under § 75.53(e) and (f). Electronic submittal of all monitoring plan information, including the hardcopy portions, is permissible, provided that a paper copy can be furnished upon request.
- (ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.59(a)(9), and the results of any failed tests that affect data validation.
- (iii) [Reserved]
- (iv) Designated representative signature certifying the accuracy of the submission.

(c) **Format.** The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator. The hardcopy test results shall be submitted in a format suitable for review and shall include the information in § 75.59(a)(9).

- (d) Consistent with § 72.21 of this chapter, a hardcopy cover letter signed by the Designated Representative (DR) shall accompany the hardcopy portion of each certification or recertification application. The cover letter shall include the certification statement described in § 72.21(b) of this chapter, and shall be submitted to the applicable EPA Regional Office and to the appropriate State or local air pollution control agency. For the electronic portion of a certification or recertification application submitted to the Administrator, a cover letter is not required. However, at his or her discretion, the DR may include important explanatory text or comments with the electronic portion of a certification or recertification application, so long as the information is provided in an electronic format compatible with the other data required to be reported under this section.

[64 FR 28621, May 26, 1999, as amended at 67 FR 40443, June 12, 2002; 73 FR 4357, Jan. 24, 2008; 76 FR 17317, Mar. 28, 2011]

§ 75.64 Quarterly reports.

- (a) **Electronic submission.** The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification or the calendar quarter corresponding to the relevant deadline for initial certification in § 75.4(a), (b), or (c). The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For an affected unit subject to § 75.4(d) that is shutdown on the relevant compliance date in § 75.4(a) or has been placed in long-term cold storage (as defined in § 72.2 of this chapter), quarterly reports are not required. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences commercial operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced commercial operation of the unit). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. For any provisionally-certified monitoring system, § 75.20(a)(3) shall apply for initial certifications, and § 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Prior to January 1, 2008, each electronic report shall include for each affected unit (or group of units using a common stack), the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section. During the time period of January 1, 2008 to January 1, 2009, each electronic report shall include, either the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section or the information provided in paragraphs (a)(3) through (a)(15) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a)(3) through (a)(15) of this section only. Each electronic report shall also include the date of report generation.

(1) Facility information:

(i) Identification, including:

- (A) Facility/ORISPL number;
- (B) Calendar quarter and year for the data contained in the report; and
- (C) Version of the electronic data reporting format used for the report.

(ii) Location, including:

- (A) Plant name and facility ID;

- (B) EPA AIRS facility system ID;
 - (C) State facility ID;
 - (D) Source category/type;
 - (E) Primary SIC code;
 - (F) State postal abbreviation;
 - (G) County code; and
 - (H) Latitude and longitude.
- (2) The information and hourly data required in § 75.53 and §§ 75.57 through 75.59, excluding the following:
- (i) Descriptions of adjustments, corrective action, and maintenance;
 - (ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
 - (iii) Opacity data listed in or § 75.57(f), and in § 75.59(a)(8);
 - (iv) For units with SO₂ or NO_x add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);
 - (v) [Reserved]
 - (vi) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;
 - (vii) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;
 - (viii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or “K” factors required by § 75.59(a)(5)(vi) or § 75.59(a)(5)(vii);
 - (ix) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D;
 - (x) Information required by §§ 75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;
 - (xi) Stratification test results required as part of the RATA supplementary records under § 75.59(a)(7);
 - (xii) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance; and
 - (xiii) Supplementary RATA information required under § 75.59(a)(7), except that:

- (A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;
 - (B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;
 - (C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and
 - (D) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.
- (3) Facility identification information, including:
- (i) Facility/ORISPL number;
 - (ii) Calendar quarter and year for the data contained in the report; and
 - (iii) Version of the electronic data reporting format used for the report.
- (4) In accordance with § 75.62(a)(1), if any monitoring plan information required in § 75.53 requires an update, either under § 75.53(b) or elsewhere in this part, submission of the electronic monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly electronic data report for the appropriate quarter in which the update is required.
- (5) The daily calibration error test and daily interference check information required in § 75.59(a)(1) and (a)(2) must always be included in the electronic quarterly emissions report. All other certification, quality assurance, and quality control information in § 75.59 that is not excluded from electronic reporting under paragraph (a)(2) or (a)(7) of this section shall be submitted separately, either prior to or concurrent with the submittal of the relevant electronic quarterly emissions report. However, reporting of the information in § 75.59(a)(9)(x) is not required until September 26, 2011, and reporting of the information in § 75.59(a)(15), (b)(6), and (d)(4) is not required until March 27, 2012.
- (6) The information and hourly data required in §§ 75.57 through 75.59, and daily calibration error test data, daily interference check, and off-line calibration demonstration information required in § 75.59(a)(1) and (2).
- (7) Notwithstanding the requirements of paragraphs (a)(4) through (a)(6) of this section, the following information is excluded from electronic reporting:
- (i) Descriptions of adjustments, corrective action, and maintenance;
 - (ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
 - (iii) Opacity data listed in § 75.57(f), and in § 75.59(a)(8);

- (iv) For units with SO₂ or NO_x add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);
- (v) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;
- (vi) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;
- (vii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or "K" factors required by § 75.59(a)(5)(vi) or § 75.59(a)(5)(vii);
- (viii) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D of this part;
- (ix) Information required by §§ 75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;
- (x) Stratification test results required as part of the RATA supplementary records under § 75.59(a)(7);
- (xi) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance;
- (xii) Supplementary RATA information required under § 75.59(a)(7)(i) through § 75.59(a)(7)(v), except that:
 - (A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;
 - (B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;
 - (C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and
 - (D) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied; and
- (xiii) The certification required by section 6.1.2(b) of appendix A to this part and recorded under § 75.57(a)(7).
- (8) Tons (rounded to the nearest tenth) of SO₂ emitted during the quarter and cumulative SO₂ emissions for the calendar year.

- (9) Average NO_x emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_x emission rate for the calendar year.
- (10) Tons of CO₂ emitted during quarter and cumulative CO₂ emissions for calendar year.
- (11) Total heat input (mmBtu) for quarter and cumulative heat input for calendar year.
- (12) Unit or stack or common pipe header operating hours for quarter and cumulative unit or stack or common pipe header operating hours for calendar year.
- (13) For low mass emissions units for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) to calculate NO_x mass emissions, the designated representative must also report tons (rounded to the nearest tenth) of NO_x emitted during the quarter and cumulative NO_x mass emissions for the calendar year.
- (14) For low mass emissions units using the optional long term fuel flow methodology under § 75.19(c), for each quarter report the long term fuel flow for each fuel according to § 75.58(f)(2).
- (15) For units using the optional fuel flow to load procedure in section 2.1.7 of appendix D to this part, report both the fuel flow-to-load baseline data and the results of the fuel flow-to-load test each quarter.
- (b) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports, submitted to the Administrator pursuant to § 75.53, represent current operating conditions.
- (c) **Compliance certification.** The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of § 75.34(a)(1), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO₂ or NO_x emissions, pursuant to § 75.34.
- (d) **Electronic format.** Each quarterly report shall be submitted in a format to be specified by the Administrator, including both electronic submission of data and (unless otherwise approved by the Administrator) electronic submission of compliance certifications.
- (e) [Reserved]
- (f) **Method of submission.** Beginning with the quarterly report for the first quarter of the year 2001, all quarterly reports shall be submitted to EPA by direct computer-to-computer electronic transfer via EPA-provided software, unless otherwise approved by the Administrator.
- (g) At his or her discretion, the DR may include important explanatory text or comments with an electronic quarterly report submittal, so long as the information is provided in a format that is compatible with the other data required to be reported under this section.

[64 FR 28622, May 26, 1999, as amended at 67 FR 40444, June 12, 2002; 73 FR 4357, Jan. 24, 2008; 76 FR 17317, Mar. 28, 2011]

§ 75.65 Opacity reports.

The owner or operator or designated representative shall report excess emissions of opacity recorded under § 75.57(f) to the applicable State or local air pollution control agency.

[64 FR 28623, May 26, 1999, as amended at 67 FR 40444, June 12, 2002]

§ 75.66 Petitions to the Administrator.

- (a) **General.** The designated representative for an affected unit subject to the requirements of this part may submit a petition to the Administrator requesting that the Administrator exercise his or her discretion to approve an alternative to any requirement prescribed in this part or incorporated by reference in this part. Any such petition shall be submitted in accordance with the requirements of this section. The designated representative shall comply with the signatory requirements of § 72.21 of this chapter for each submission.
- (b) **Alternative flow monitoring method petition.** In cases where no location exists for installation of a flow monitor in either the stack or the ducts serving an affected unit that satisfies the minimum physical siting criteria in appendix A of this part or where installation of a flow monitor in either the stack or duct is demonstrated to the satisfaction of the Administrator to be technically infeasible, the designated representative for the affected unit may petition the Administrator for an alternative method for monitoring volumetric flow. The petition shall, at a minimum, contain the following information:
 - (1) Identification of the affected unit(s);
 - (2) Description of why the minimum siting criteria cannot be met within the existing ductwork or stack(s). This description shall include diagrams of the existing ductwork or stack, as well as documentation of any attempts to locate a flow monitor; and
 - (3) Description of proposed alternative method for monitoring flow.
- (c) **Alternative to standards incorporated by reference.** The designated representative for an affected unit may apply to the Administrator for an alternative to any standard incorporated by reference and prescribed in this part. The designated representative shall include the following information in an application:
 - (1) A description of why the prescribed standard is not being used;
 - (2) A description and diagram(s) of any equipment and procedures used in the proposed alternative;
 - (3) Information demonstrating that the proposed alternative produces data acceptable for use in the Acid Rain Program, including accuracy and precision statements, NIST traceability certificates or protocols, or other supporting data, as applicable to the proposed alternative.
- (d) **Alternative monitoring system petitions.** The designated representative for an affected unit may submit a petition to the Administrator for approval and certification of an alternative monitoring system or component according to the procedure in subpart E of this part. Each petition shall contain the information and data specified in subpart E, including the information specified in § 75.48, in a format to be specified by the Administrator.
- (e) **Parametric monitoring procedure petitions.** The designated representative for an affected unit may submit a petition to the Administrator, where each petition shall contain the information specified in § 75.58(b) for the use of a parametric monitoring method. The Administrator will either:

- (1) Publish a notice in the FEDERAL REGISTER indicating receipt of a parametric monitoring procedure petition; or
- (2) Notify interested parties of receipt of a parametric monitoring petition.

(f) [Reserved]

(g) ***Petitions for emissions or heat input apportionments.*** The designated representative of an affected unit shall provide information to describe a method for emissions or heat input apportionment under §§ 75.13, 75.16, 75.17, or appendix D of this part. This petition may be submitted as part of the monitoring plan. Such a petition shall contain, at a minimum, the following information:

- (1) A description of the units, including their fuel type, their boiler type, and their categorization as Phase I units, substitution units, compensating units, Phase II units, new units, or non-affected units;
- (2) A formula describing how the emissions or heat input are to be apportioned to which units;
- (3) A description of the methods and parameters used to apportion the emissions or heat input; and
- (4) Any other information necessary to demonstrate that the apportionment method accurately measures emissions or heat input and does not underestimate emissions or heat input from affected units.

(h) ***Partial recertification petition.*** The designated representative of an affected unit may provide information and petition the Administrator to specify which of the certification tests required by § 75.20 apply for partial recertification of the affected unit. Such a petition shall include the following information:

- (1) Identification of the monitoring system(s) being changed;
- (2) A description of the changes being made to the system;
- (3) An explanation of why the changes are being made; and
- (4) A description of the possible effect upon the monitoring system's ability to measure, record, and report emissions.

(i) [Reserved]

(j) ***Petition for alternative method of accounting for emissions prior to completion of certification tests.*** The designated representative for an affected unit may submit a petition to the Administrator to use an alternative to the procedures in § 75.4(d)(3), (e)(3), (f)(3) or (g)(3) to account for emissions during the period between the compliance date for a unit and the completion of certification testing for that unit. The designated representative shall include:

- (1) Identification of the affected unit(s);
- (2) A detailed explanation of the alternative method to account for emissions of the following parameters, as applicable: SO₂ mass emissions (in lbs), NO_x emission rate (in lbs/mmBtu), CO₂ mass emissions (in lbs) and, if the unit is subject to the requirements of subpart H of this part, NO_x mass emissions (in lbs); and
- (3) A demonstration that the proposed alternative does not underestimate emissions.

- (k) *Petition for an alternative to the stabilization criteria for the cycle time test in section 6.4 of appendix A to this part.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative stabilization criteria for the cycle time test in section 6.4 of appendix A to this part, if the installed monitoring system does not record data in 1-minute or 3-minute intervals. The designated representative shall provide a description of the alternative criteria.
- (l) *Any other petitions to the Administrator under this part.* Except for petitions addressed in paragraphs (b) through (k) of this section, any petition submitted under this paragraph shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:
- (1) Identification of the affected plant and unit(s);
 - (2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;
 - (3) A description and diagram of any equipment and procedures used in the proposed alternative, if applicable;
 - (4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and is consistent with the purposes of this part and of section 412 of the Act and that any adverse effect of approving such alternative will be *de minimis*; and
 - (5) Any other relevant information that the Administrator may require.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26540, 26569, May 17, 1995; 61 FR 59162, Nov. 20, 1996; 64 FR 28623, May 26, 1999; 67 FR 40444, June 12, 2002; 73 FR 4358, Jan. 24, 2008]

§ 75.67 Retired units petitions.

- (a) [Reserved]
- (b) For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter that will be permanently retired and governed upon entry into the Opt-in Program by a thermal energy plan in accordance with § 74.47 of this chapter, an exemption from the requirements of this part, including the requirement to install and certify a continuous emissions monitoring system, may be obtained from the Administrator if the designated representative submits to the Administrator a petition for such an exemption prior to the deadline in § 75.4 by which the continuous emission or opacity monitoring systems must complete the required certification tests.

[60 FR 17131, Apr. 4, 1995, as amended at 60 FR 26541, May 17, 1995; 62 FR 55487, Oct. 24, 1997]

§ 75.68 Temporary modifications to otherwise applicable quality-assurance requirements during the COVID-19 national emergency.

- (a) Notwithstanding any other provision of this part, during and following the emergency period defined in paragraph (a)(1) of this section, the provisions of this section shall apply for purposes of reporting the data that are required to be reported under this part and completing the tests that are required to be completed under this part.
- (1) For purposes of this section, the emergency period begins on March 13, 2020, the date of the declaration of a national emergency concerning the novel coronavirus disease (COVID-19) outbreak by the President of the United States in accordance with 50 U.S.C. 1621, and concludes 60 days after

the date of termination of the national emergency by Congress or the President in accordance with 50 U.S.C. 1622, provided that the emergency period under this section shall not extend past the expiration of the effectiveness of this section.

- (2) The provisions of this section shall apply with respect to the following tests that are required to be completed under this part:
 - (i) Any quality-assurance test of a continuous emission monitoring system required under appendix B to this part or § 75.74(c).
 - (ii) Any quality-assurance test of a fuel flowmeter required under section 2.1.6 of appendix D to this part or § 75.74(c).
 - (iii) Any certification or recertification test of a continuous emission monitoring system required under § 75.20 or § 75.70(d).
 - (iv) Any certification test of a fuel flowmeter required under section 2.1.5 of appendix D to this part or § 75.70(d).
 - (v) Any periodic analysis of fuel sulfur content, density, or gross calorific value required under section 2.2 or 2.3 of appendix D to this part, provided that there have been no changes in the fuel supply since the most recent previous fuel analysis that would reasonably be expected to cause a change in such fuel characteristics.
 - (vi) Any periodic retest of NO_x emission rates required under section 2.2 of appendix E to this part.
 - (vii) Any periodic retest of fuel-and-unit-specific NO_x emission rates required under § 75.19(c)(4)(i)(D) that is required only because of the passage of time and not because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls.
- (3) Following a failure to complete by the applicable deadline (or by the end of any grace period following the deadline) any required quality-assurance test or tests described in paragraph (a)(2)(i) or (ii) of this section for any continuous emission monitoring system or fuel flowmeter under this part, for any subsequent operating hour in the emergency period prior to completion of the test or tests in accordance with paragraph (a)(6)(i) of this section, the owner or operator of an affected unit may continue to report data determined using measurements obtained from the continuous emission monitoring system or fuel flowmeter as valid, provided that the following conditions are met:
 - (i) But for the failure to complete the quality-assurance test or tests, the data obtained from the monitoring system would be considered valid without the benefit of the provisions of this section;
 - (ii) The reason for failure to complete each such quality-assurance test is travel, plant access, or other safety restrictions implemented to address the COVID-19 national emergency; and
 - (iii) The owner or operator creates and maintains the records specified in paragraph (a)(7)(i) of this section and the designated representative submits the notifications required under paragraphs (a)(7)(ii) and (iii) of this section.
- (4) Following a failure to complete by the applicable deadline any required certification or recertification test or tests described in paragraph (a)(2)(iii) or (iv) of this section for any continuous emission monitoring system or fuel flowmeter under this part, for any subsequent operating hour in an

emergency period prior to completion of the test or tests in accordance with paragraph (a)(6)(i) of this section, the owner or operator of an affected unit may continue to report data determined using measurements obtained from the continuous emission monitoring system or fuel flowmeter as conditionally valid provided that the following conditions are met:

- (i) But for the failure to complete the certification or recertification test or tests, the data obtained from the monitoring system would be considered conditionally valid without the benefit of the provisions of this section;
 - (ii) The reason for failure to complete each such certification or recertification test is travel, plant access, or other safety restrictions implemented to address the COVID-19 national emergency; and
 - (iii) The owner or operator creates and maintains the records specified in paragraph (a)(7)(i) of this section and the designated representative submits the notifications required under paragraphs (a)(7)(ii) and (iii) of this section.
- (5) Following a failure to complete by the applicable deadline any required periodic analysis of fuel characteristics under appendix D to this part described in paragraph (a)(2)(v) of this section or any required periodic NO_x emission rate testing under appendix E to this part or § 75.19 described in paragraph (a)(2)(vi) or (vii) of this section, for any subsequent operating hour during the emergency period prior to completion of the analysis or testing in accordance with paragraph (a)(6)(i) of this section, the owner or operator of an affected unit using the methodology in appendix D may continue to report data determined using the fuel characteristics authorized for use under the regulations following the most recent previous analysis for that fuel, the owner or operator of an affected unit using the methodology in appendix E may continue to report data determined using the correlation curve developed from the most recent previous appendix E NO_x emission rate testing, and the owner or operator of an affected unit using a fuel-and-unit-specific emission rate under the LME methodology in § 75.19(c)(1)(iv) may continue to report data determined using the fuel-and-unit-specific emission rate developed from the most recent previous LME NO_x emission rate testing, provided that the following conditions are met:
- (i) But for the failure to complete the appendix D fuel analysis or the appendix E or LME NO_x emission rate testing, the data obtained from the appendix D, appendix E, or LME monitoring methodology would be considered valid without the benefit of the provisions of this section;
 - (ii) The reason for failure to complete each such appendix D fuel analysis or appendix E or LME NO_x emission rate test is travel, plant access, or other safety restrictions implemented to address the COVID-19 national emergency; and
 - (iii) The owner or operator creates and maintains the records specified in paragraph (a)(7)(i) of this section and the designated representative submits the notifications required under paragraphs (a)(7)(ii) and (iii) of this section.
- (6)
- (i) Each quality-assurance test, certification or recertification test, appendix D fuel analysis, and appendix E or LME NO_x emission rate test required under this part that was not completed for a unit by the applicable deadline (or by the end of any grace period following the deadline) must be completed as soon as practicable following the end of travel, plant access, or other safety

restrictions implemented to address the COVID-19 national emergency that affect that unit or the personnel or supplies required to complete the analysis or testing for that unit, but in no event later than the conclusion of the emergency period as defined in paragraph (a)(1) of this section.

- (ii) If a test or analysis for which a deadline is established under paragraph (a)(6)(i) of this section is not completed by that deadline, the test or analysis shall be completed as soon as practicable thereafter, and for each operating hour following that deadline until completion of the test or analysis, the owner or operator shall report substitute data as if the originally applicable deadline for the test or analysis were the deadline under paragraph (a)(6)(i) of this section.
 - (iii) For purposes of determining the applicable deadline for the next quality-assurance test, appendix D fuel analysis, or appendix E or LME NO_x emission rate test required under this part after a delayed quality-assurance test, appendix D fuel analysis, or appendix E or LME NO_x emission rate test is completed or due to be completed in accordance with paragraph (a)(6)(i) of this section, the delayed test or analysis shall be considered to have been completed in a timely manner as of the date on which such delayed test or analysis was actually completed or, if earlier, the deadline for completion of the delayed test or analysis under paragraph (a)(6)(i) of this section.
- (7) The following recordkeeping and reporting requirements shall apply to any use of the procedures under paragraphs (a)(3) through (6) of this section:
- (i) The owner or operator of an affected unit reporting data under paragraph (a)(3), (4), or (5) of this section shall maintain records documenting the reasons for failure to complete by the applicable deadline each test or analysis referenced in such paragraph and demonstrating that such failure is caused by travel, plant access, or other safety restrictions implemented to address the COVID-19 national emergency. The owner or operator shall also maintain records documenting when any such travel, plant access, or other safety restrictions impairing the ability to complete testing or analyses for that unit ceased to apply. The records shall be maintained on site at the source in a form suitable for inspection for a period of three years from the date of each record.
 - (ii) By five business days after the applicable deadline for a test or analysis referenced in paragraph (a)(3), (4), or (5) of this section, the designated representative shall submit to the Administrator, by email transmitted to camdpetitions@epa.gov, a notification containing the following information:
 - (A) Facility ID (ORIS);
 - (B) Facility name;
 - (C) Monitoring location ID and/or unit ID;
 - (D) Identification of the quality-assurance test, certification or recertification test, appendix D fuel analysis, or appendix E or LME NO_x emission rate test for which the notification is being submitted;
 - (E) Identification of the applicable deadline for the test or analysis under part 75 (not including any applicable grace period);

- (F) A detailed explanation of the reason for failure to complete the test or analysis by the applicable deadline under part 75, including an explanation of how such failure is caused by travel, plant access, or other safety restrictions implemented to address the COVID-19 national emergency;
 - (G) The certification statements in § 72.21(b)(1) and (2) of this chapter.
- (iii) By five business days after the completion in accordance with paragraph (a)(6)(i) or (ii) of this section of a delayed test or analysis referenced in paragraph (a)(3), (4), or (5) of this section, the designated representative shall submit to the Administrator, by email transmitted to camdpetitions@epa.gov, a notification containing the following information:
- (A) Facility ID (ORIS);
 - (B) Facility name;
 - (C) Monitoring location ID and/or unit ID;
 - (D) Identification of the quality-assurance test, certification or recertification test, appendix D fuel analysis, or appendix E or LME NO_x emission rate test for which the notification is being submitted;
 - (E) Identification of the date as of which travel, plant access, or other safety restrictions previously impairing the ability to complete the delayed test or analysis for the unit no longer applied;
 - (F) Identification of the date as of which the test or analysis was completed in accordance with paragraph (a)(6)(i) or (ii) of this section; and
 - (G) The certification statements in § 72.21(b)(1) and (2) of this chapter.
- (iv) With respect to any test or analysis of a type that is required to be performed more frequently than once per unit operating quarter, a series of such required tests or analyses may be treated as a single test or analysis for purposes of a notification submitted under paragraph (a)(7)(ii) or (iii) of this section, with the notification under paragraph (a)(7)(ii) to be submitted by five business days after the first failure to perform such a test or analysis by the applicable deadline and the notification under paragraph (a)(7)(iii) to be submitted by five business days after the first completion of such a test or analysis in accordance with paragraph (a)(6)(i) or (ii) of this section.
- (v) A notification submitted under paragraph (a)(7)(ii) or (iii) of this section may include information for more than one required test for a given unit or monitoring location, provided that each item of information required to be included in such notification pursuant to paragraphs (a)(7)(ii)(D) through (F) of this section or paragraphs (a)(7)(iii)(D) through (F) of this section is provided separately for each required test included in the notification.
- (vi) No claim of confidentiality may be asserted with respect to any information included in a notification submitted under paragraph (a)(7)(ii) or (iii) of this section.
- (vii) Notwithstanding the deadlines for submission of notifications in paragraphs (a)(7)(ii), (iii), and (iv) of this section, no such notification from any owner or operator shall be due less than 30 days after the effective date of this section.

- (b) The requirements of this section are effective from April 22, 2020 and, except for those in paragraphs (a)(6)(ii) and (iii) and (a)(7)(i) of this section, shall cease to have effect October 19, 2020.

[85 FR 22372, Apr. 22, 2020]

Subpart H—NO_x Mass Emissions Provisions

Source: 63 FR 57507, Oct. 27, 1998, unless otherwise noted.

§ 75.70 NO_x mass emissions provisions.

- (a) **Applicability.** The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_x mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.
- (1) For purposes of this subpart, the term “affected unit” shall mean any unit that is subject to a State or federal NO_x mass emission reduction program requiring compliance with this subpart, the term “non-affected unit” shall mean any unit that is not subject to such a program, the term “permitting authority” shall mean the permitting authority under an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, and the term “designated representative” shall mean the responsible party under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to NO_x concentration, flow rate, NO_x emission rate and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or federal NO_x mass emission reduction program. When applying these requirements, the term “affected unit” shall mean any unit that is subject to a State or federal NO_x mass emission reduction program requiring compliance with this subpart, the term “permitting authority” shall mean the permitting authority under an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, and the term “designated representative” shall mean the responsible party under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. The requirements of this part for SO₂, CO₂ and opacity monitoring, recordkeeping and reporting do not apply to units that are subject to a State or federal NO_x mass emission reduction program only and are not affected units with an Acid Rain emission limitation.
- (b) **Compliance dates.** The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (c) **Prohibitions.**
- (1) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

- (2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_x to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part, except as provided in § 75.74.
- (3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under § 75.71, except as provided in § 75.74.
- (4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:
 - (i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or federal NO_x mass emission reduction program that adopts the requirements of this subpart;
 - (ii) The owner or operator is monitoring NO_x mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or
 - (iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.61.

(d) **Initial certification and recertification procedures.**

- (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures in § 75.20 of this part, except that the owner or operator shall meet any additional requirements set forth in an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart for any additional NO_x-diluent CEMS, flow monitors, diluent monitors or NO_x concentration monitoring system required under the NO_x mass emissions provisions of § 75.71 or the common stack provisions in § 75.72.

(e) **Quality assurance and quality control requirements.** For units that use continuous emission monitoring systems to account for NO_x mass emissions, the owner or operator shall meet the applicable quality assurance and quality control requirements in § 75.21, appendix B to this part, and § 75.74(c) for the NO_x-diluent continuous emission monitoring systems, flow monitoring systems, NO_x concentration monitoring systems, moisture monitoring systems, and diluent monitors required under § 75.71. Units using the low mass emissions excepted methodology under § 75.19 shall meet the applicable quality

assurance requirements of that section, except as otherwise provided in § 75.74(c). Units using excepted monitoring methods under appendices D and E to this part shall meet the applicable quality assurance requirements of those appendices.

(f) **Missing data procedures.** Except as provided in § 75.34, paragraph (g) of this section, and § 75.74(c)(7), the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

- (1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the applicable missing data procedures in §§ 75.31 through 75.37 whenever the unit combusts fuel and:
 - (i) A valid, quality-assured hour of NO_x emission rate data (in lb/mmBtu) has not been measured and recorded for a unit by a certified NO_x-diluent continuous emission monitoring system or by an approved monitoring system under subpart E of this part;
 - (ii) A valid, quality-assured hour of flow data (in scfh) has not been measured and recorded for a unit from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part;
 - (iii) A valid, quality-assured hour of heat input rate data (in mmBtu/hr) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO₂ or O₂) monitor or by an approved alternative monitoring system under subpart E of this part, where heat input is required either for calculating NO_x mass or allocating allowances under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart;
 - (iv) A valid, quality-assured hour of NO_x concentration data (in ppm) has not been measured and recorded by a certified NO_x concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_x concentration monitoring system with a flow monitor, to calculate NO_x mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_x concentration monitoring system shall be the same as the procedures specified for a NO_x-diluent continuous emission monitoring system under §§ 75.31, 75.32, and 75.33; or
 - (v) A valid, quality-assured hour of moisture data (in percent H₂O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in § 75.11(b) or § 75.12(b), is used to account for the hourly moisture content of the stack gas.
- (2) For an owner or operator using an excepted monitoring system under appendix D or E of this part, substitute for missing data in accordance with the missing data procedures in section 2.4 of appendix D to this part or in section 2.5 of appendix E to this part whenever the unit combusts fuel and:
 - (i) A valid, quality-assured hour of fuel flow rate data has not been measured and recorded by a certified fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part; or
 - (ii) A fuel sample value for gross calorific value, or if necessary, density or specific gravity, from a sample taken and analyzed in accordance with appendix D of this part is not available; or

- (iii) A valid, quality-assured hour of NO_x emission rate data has not been obtained according to the procedures and specifications of appendix E to this part.

(g) **Reporting data prior to initial certification.** If the owner or operator of an affected unit has not successfully completed all certification tests required by the State or federal NO_x mass emission reduction program that adopts the requirements of this subpart by the applicable date required by that program, he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, consistent with the monitoring equipment to be certified:

- (1) For units that the owner or operator intends to monitor for NO_x mass emissions using NO_x emission rate and heat input rate, the maximum potential NO_x emission rate and the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.
- (2) For units that the owner or operator intends to monitor for NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system, the maximum potential concentration of NO_x and the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part;
- (3) For any unit, the reference methods under § 75.22 of this part.
- (4) For any unit using the low mass emission excepted monitoring methodology under § 75.19, the procedures in paragraphs (g)(1) or (2) of this section.
- (5) Any unit using the procedures in paragraph (g)(2) of this section that is required to report heat input for purposes of allocating allowances shall also report the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.
- (6) For any unit using continuous emissions monitors, the conditional data validation procedures in § 75.20(b)(3)(ii) through (b)(3)(ix).

(h) **Petitions.**

- (1) The designated representative of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or federal NO_x mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.
- (2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72 shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (h)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (3)

- (i) The designated representative of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by the Administrator and by the permitting authority if required by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

[63 FR 57507, Oct. 27, 1998, as amended at 64 FR 28624, May 26, 1999; 67 FR 40444, June 12, 2002]

§ 75.71 Specific provisions for monitoring NO_x and heat input for the purpose of calculating NO_x mass emissions.

- (a) **Coal-fired units.** The owner or operator of a coal-fired affected unit shall either:
 - (1) Meet the general operating requirements in § 75.10 for a NO_x-diluent continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor, an O₂ or CO₂ diluent gas monitor, and a data acquisition and handling system) to measure NO_x emission rate and for a flow monitoring system and an O₂ or CO₂ diluent gas monitoring system to measure heat input rate, except as provided in accordance with subpart E of this part; or
 - (2) Meet the general operating requirements in § 75.10 for a NO_x concentration monitoring system (consisting of a NO_x pollutant concentration monitor and a data acquisition and handling system) to measure NO_x concentration and for a flow monitoring system. In addition, if heat input is required to be reported under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating requirements for a flow monitoring system and an O₂ or CO₂ monitoring system to measure heat input rate. These requirements must be met, except as provided in accordance with subpart E of this part.
- (b) **Moisture correction.**
 - (1) If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu (e.g., if the NO_x pollutant concentration monitor in a NO_x-diluent monitoring system measures on a different moisture basis from the diluent monitor), or to calculate the heat input rate, the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.12(b).
 - (2) If a correction for the stack gas moisture content is needed to properly calculate NO_x mass emissions in tons, in the case where a NO_x concentration monitoring system which measures on a dry basis is used with a flow rate monitor to determine NO_x mass emissions, the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.11(b) except that the term "SO₂" shall be replaced by the term "NO_x."

- (3) If a correction for the stack gas moisture content is needed to properly calculate NO_x mass emissions, in the case where a diluent monitor that measures on a dry basis is used with a flow rate monitor to determine heat input rate, which is then multiplied by the NO_x emission rate, the owner or operator shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as described in § 75.11(b).
- (c) **Gas-fired nonpeaking units or oil-fired nonpeaking units.** The owner or operator of an affected unit that, based on information submitted by the designated representative in the monitoring plan, qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, shall either:
 - (1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or
 - (2) Meet the general operating requirements in § 75.10 for a NO_x-diluent continuous emission monitoring system, except as provided in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input rate. However, for a common pipe configuration, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart, unless all of the units served by the common pipe are affected units and have similar efficiencies; or
 - (3) Meet the requirements of the low mass emission excepted methodology under paragraph (e)(2) of this section and under § 75.19, if applicable.
- (d) **Gas-fired or oil-fired peaking units.** The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall either:
 - (1) Meet the requirements of paragraph (c) of this section; or
 - (2) Use the procedures in appendix D to this part for determining hourly heat input and the procedure specified in appendix E to this part for estimating hourly NO_x emission rate. However, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies. In addition, if after certification of an excepted monitoring system under appendix E to this part, the operation of a unit that reports emissions on an annual basis under § 75.74(a) of this part exceeds a capacity factor of 20.0 percent in any calendar year or exceeds an annual capacity factor of 10.0 percent averaged over three years, or the operation of a unit that reports emissions on an ozone season basis under § 75.74(b) of this part exceeds a capacity factor of 20.0 percent in any ozone season or exceeds an ozone season capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c)(1) or (c)(2) of this section by no later than December 31 of the following calendar year. If the required CEMS are not installed and certified by that date, the owner or operator shall report hourly NO_x mass emissions as the product of the maximum potential NO_x emission rate (MER) and the maximum hourly heat input of the unit (as defined in § 72.2 of this chapter), starting with the first unit operating hour after the deadline and continuing until the CEMS are provisionally certified.
- (e) **Low mass emissions units.** Notwithstanding the requirements of paragraphs (c) and (d) of this section, for an affected unit using the low mass emissions (LME) unit under § 75.19 to estimate hourly NO_x emission rate, heat input and NO_x mass emissions, the owner or operator shall calculate the ozone season NO_x mass emissions by summing all of the estimated hourly NO_x mass emissions in the ozone season, as determined under § 75.19 (c)(4)(ii)(A), and dividing this sum by 2000 lb/ton.

- (f) **Other units.** The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

[63 FR 57508, Oct. 27, 1998, as amended at 64 FR 28624, May 26, 1999; 67 FR 40444, 40445, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4358, Jan. 24, 2008]

§ 75.72 Determination of NO_x mass emissions for common stack and multiple stack configurations.

The owner or operator of an affected unit shall either: calculate hourly NO_x mass emissions (in lbs) by multiplying the hourly NO_x emission rate (in lbs/mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time (as defined in § 72.2), or, as provided in paragraph (e) of this section, calculate hourly NO_x mass emissions from the hourly NO_x concentration (in ppm) and the hourly stack flow rate (in scfh). Only one methodology for determining NO_x mass emissions shall be identified in the monitoring plan for each monitoring location at any given time. The owner or operator shall also calculate quarterly and cumulative year-to-date NO_x mass emissions and cumulative NO_x mass emissions for the ozone season (in tons) by summing the hourly NO_x mass emissions according to the procedures in section 8 of appendix F to this part.

- (a) **Unit utilizing common stack with other affected unit(s).** When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:
- (1) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system and a flow monitoring system in the common stack, record the combined NO_x mass emissions for the units exhausting to the common stack, and, for purposes of determining the hourly unit heat input rates, either:
 - (i) Apportion the common stack heat input rate to the individual units according to the procedures in § 75.16(e)(3); or
 - (ii) Install, certify, operate, and maintain a flow monitoring system and diluent monitor in the duct to the common stack from each unit; or
 - (iii) If any of the units using the common stack are eligible to use the procedures in appendix D to this part,
 - (A) Use the procedures in appendix D to this part to determine heat input rate for that unit; and
 - (B) Install, certify, operate, and maintain a flow monitoring system and a diluent monitor in the duct to the common stack for each remaining unit; or
 - (2) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system in the duct to the common stack from each unit and, for purposes of heat input determination, either:
 - (i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each unit; or
 - (ii) For any unit using the common stack and eligible to use the procedures in appendix D to this part,
 - (A) Use the procedures in appendix D to determine heat input rate for that unit; and

- (B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit.
- (b) **Unit utilizing common stack with nonaffected unit(s).** When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:
 - (1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system in the duct to the common stack from each affected unit and, for purposes of heat input determination,
 - (i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each affected unit; or
 - (ii) For any affected unit using the common stack and eligible to use the procedures in appendix D to this part,
 - (A) Use the procedures in appendix D to determine heat input for that unit; however, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies; and
 - (B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or
 - (2) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system in the common stack; and
 - (i) Designate the nonaffected units as affected units in accordance with the applicable State or federal NO_x mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or
 - (ii) Install, certify, operate, and maintain a flow monitoring system in the common stack and a NO_x-diluent continuous emission monitoring system in the duct to the common stack from each nonaffected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_x mass emissions from the affected units as the difference between NO_x mass emissions measured in the common stack and NO_x mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_x mass emissions from the affected units are not underestimated. In addition, the owner or operator shall also either:
 - (A) Install, certify, operate, and maintain a flow monitoring system in the duct from each nonaffected unit or,
 - (B) For any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input rate using the procedures in appendix D for that unit. However, for a common pipe serving both affected and non-affected units, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart. For any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitoring system in the duct to the common stack; or

- (iii) Install a flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_x mass emissions for the affected units for recordkeeping and compliance purposes, in accordance with paragraph (a) of this section; or
 - (iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_x mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_x mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_x mass emissions from the affected units are not underestimated.
- (c) **Unit with a main stack and a bypass stack.** Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack to avoid the installed NO_x-diluent continuous emissions monitoring system or NO_x concentration monitoring system, the owner and operator shall either:
- (1) Install, certify, operate, and maintain separate NO_x-diluent continuous emissions monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate NO_x mass emissions for the unit as the sum of the NO_x mass emissions measured at the two stacks;
 - (2) Monitor NO_x mass emissions at the main stack using a NO_x-diluent CEMS and a flow monitoring system and measure NO_x mass emissions at the bypass stack using the reference methods in § 75.22(b) for NO_x concentration, flow rate, and diluent gas concentration, or NO_x concentration and flow rate, and calculate NO_x mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or
 - (3) Install, certify, operate, and maintain a NO_x-diluent CEMS and a flow monitoring system only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report NO_x mass emissions as follows. If the unit heat input is determined using a flow monitor and a diluent monitor, report NO_x mass emissions using the maximum potential NO_x emission rate, the maximum potential flow rate, and either the maximum potential CO₂ concentration or the minimum potential O₂ concentration (as applicable). The maximum potential NO_x emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_x mass emissions as the product of the maximum potential NO_x emission rate and the actual measured hourly heat input rate. Alternatively, for a unit with NO_x add-on emission controls, for each unit operating hour in which the bypass stack is used but the add-on NO_x emission controls are not bypassed, the owner or operator may report the maximum controlled NO_x emission rate (MCR) instead of the maximum potential NO_x emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B to this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_x add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part by replacing the words “maximum potential NO_x emission rate (MER)” with the words “maximum controlled NO_x emission rate (MCR)” and by using the NO_x MEC in the calculations instead of the NO_x MPC.

- (d) **Unit with multiple stack or duct configuration.** When the flue gases from an affected unit discharge to the atmosphere through more than one stack, or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:
- (1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system and a flow monitoring system in each of the multiple stacks and determine NO_x mass emissions from the affected unit as the sum of the NO_x mass emissions recorded for each stack. If another unit also exhausts flue gases into one of the monitored stacks, the owner or operator shall comply with the applicable requirements of paragraphs (a) and (b) of this section, in order to properly determine the NO_x mass emissions from the units using that stack;
 - (2) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system and a flow monitoring system in each of the ducts that feed into the stack, and determine NO_x mass emissions from the affected unit using the sum of the NO_x mass emissions measured at each duct; or
 - (3) If the unit is eligible to use the procedures in appendix D to this part and if the conditions and restrictions of § 75.17(c)(2) are fully met, install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or in one of the multiple stacks, (as applicable) in accordance with § 75.17(c)(2), and use the procedures in appendix D to this part to determine heat input rate for the unit.
- (e) **Units using a NO_x concentration monitoring system and a flow monitoring system to determine NO_x mass.** The owner or operator may use a NO_x concentration monitoring system and a flow monitoring system to determine NO_x mass emissions for the cases described in paragraphs (a) through (c) of this section and in paragraph (d)(1) or paragraph (d)(2) of this section (in place of a NO_x-diluent continuous emissions monitoring system and a flow monitoring system). However, this option may not be used for the case described in paragraph (d)(3) of this section. When using this approach, calculate NO_x mass according to sections 8.2 and 8.3 in appendix F to this part. In addition, if an applicable State or federal NO_x mass reduction program requires determination of a unit's heat input, the owner or operator must either:
- (1) Install, certify, operate, and maintain a CO₂ or O₂ diluent monitor in the same location as each flow monitoring system. In addition, the owner or operator must provide heat input rate values for each unit utilizing a common stack. The owner or operator may either:
 - (i) Apportion heat input rate from the common stack to each unit according to § 75.16(e)(3), where all units utilizing the common stack are affected units, or
 - (ii) Measure heat input rate to each affected unit, using a flow monitor and a CO₂ or O₂ diluent monitor in the duct from each affected unit; or
 - (2) For units that are eligible to use appendix D to this part, use the procedures in appendix D to this part to determine heat input rate for the unit. However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of appendix D to this part are not applicable to any unit that is using the provisions of this subpart to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program and that shares a common pipe with a nonaffected unit.
- (f) **Procedures for apportioning hourly NO_x mass emission rate to the unit level.** If the owner or operator of a unit determining hourly NO_x mass emission rate at a common stack under this section is subject to a State or Federal NO_x mass emissions reduction program under subpart GGGGG of part 97 of this chapter

or under a state implementation plan approved pursuant to § 52.38(b)(12) of this chapter, then on and after January 1, 2024, the owner or operator shall apportion the hourly NO_x mass emissions rate at the common stack to each unit using the common stack based on the ratio of the hourly heat input rate for each such unit to the total hourly heat input rate for all such units, in conjunction with the appropriate unit and stack operating times, according to the procedures in section 8.5.3 of appendix F to this part.

- (g) **Procedures for apportioning heat input to the unit level.** If the owner or operator of a unit using the common stack monitoring provisions in paragraphs (a) or (b) of this section does not monitor and record heat input at the unit level and the owner or operator is required to do so under an applicable State or federal NO_x mass emission reduction program, apportion heat input from the common stack to each unit according to § 75.16(e)(3).

[63 FR 57507, Oct. 27, 1998, as amended at 67 FR 40445, June 12, 2002; 73 FR 4358, Jan. 24, 2008; 88 FR 36895, June 5, 2023]

§ 75.73 Recordkeeping and reporting.

- (a) **General recordkeeping provisions.** The owner or operator of any affected unit shall maintain for each affected unit and each non-affected unit under § 75.72(b)(2)(ii) a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Except for the certification data required in § 75.57(a)(4) and the initial submission of the monitoring plan required in § 75.57(a)(5), the data shall be collected beginning with the earlier of the date of provisional certification or the compliance deadline in § 75.70(b). The certification data required in § 75.57(a)(4) shall be collected beginning with the date of the first certification test performed. The file shall contain the following information:
- (1) The information required in §§ 75.57(a)(2), (a)(4), (a)(5), (a)(6), (b), (c)(2), (d), (g), and (h).
 - (2) The information required in §§ 75.58(b)(2) or (b)(3) (for units with add-on NO_x emission controls), as applicable, (d) (as applicable for units using Appendix E to this part), and (f) (as applicable for units using the low mass emissions unit provisions of § 75.19).
 - (3) For each hour when the unit is operating, NO_x mass emission rate, calculated in accordance with section 8 of appendix F to this part.
 - (4) During the second and third calendar quarters, cumulative ozone season heat input and cumulative ozone season operating hours.
 - (5) Heat input and NO_x methodologies for the hour.
 - (6) **Specific heat input record provisions for gas-fired or oil-fired units using the procedures in appendix D to this part.** In lieu of the information required in § 75.57(c)(2), the owner or operator shall record the information in § 75.58(c) for each affected gas-fired or oil-fired unit and each non-affected gas- or oil-fired unit under § 75.72(b)(2)(ii) for which the owner or operator is using the procedures in appendix D to this part for estimating heat input.
 - (7) **Specific NO_x record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.** In lieu of recording the information in §§ 75.57(b), (c)(2), (d), and (g), the owner or operator shall record, for each hour when the unit is operating for any portion of the hour, the following information for each affected low mass emissions unit for which the owner or operator is using the low mass emissions excepted methodology in § 75.19(c):
 - (i) Date and hour;

- (ii) If one type of fuel is combusted in the hour, fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) or, if more than one type of fuel is combusted in the hour, the fuel type which results in the highest emission factors for NO_x;
- (iii) Average hourly NO_x emission rate (in lb/mmBtu, rounded to the nearest thousandth); and
- (iv) Hourly NO_x mass emissions (in lbs, rounded to the nearest tenth).

(8) Formulas from monitoring plan for total NO_x mass.

(b) **Certification, quality assurance and quality control record provisions.** The owner or operator of any affected unit shall record the applicable information in § 75.59 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).

(c) **Monitoring plan recordkeeping provisions –**

(1) **General provisions.** The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii). Except as provided in paragraph (d) or (f) of this section, a monitoring plan shall contain sufficient information on the continuous emission monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all the unit's NO_x emissions are monitored and reported.

(2) **Monitoring plan updates.** Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(3) **Contents of the monitoring plan.** Each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(h)(1)(i) and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (ii). The monitoring plan also shall include a seasonal controls indicator and an ozone season fuel-switching flag.

(d) **General reporting provisions.**

- (1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.
- (2) The designated representative for an affected unit shall submit the following for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii):
 - (i) Initial certification and recertification applications in accordance with § 75.70(d);
 - (ii) Monitoring plans in accordance with paragraph (e) of this section; and
 - (iii) Quarterly reports in accordance with paragraph (f) of this section.

- (3) **Other petitions and communications.** The designated representative for an affected unit shall submit petitions, correspondence, application forms, and petition-related test results in accordance with the provisions in § 75.70(h).
- (4) **Quality assurance RATA reports.** If requested by the permitting authority, the designated representative of an affected unit shall submit the quality assurance RATA report for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) by the later of 45 days after completing a quality assurance RATA according to section 2.3 of appendix B to this part or 15 days of receiving the request. The designated representative shall report the hardcopy information required by § 75.59(a)(9) to the permitting authority.
- (5) **Notifications.** The designated representative for an affected unit shall submit written notice to the permitting authority according to the provisions in § 75.61 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).
- (6) **Routine appendix E retest reports.** If requested by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.

(e) **Monitoring plan reporting –**

- (1) **Electronic submission.** The designated representative for an affected unit shall submit to the Administrator a complete, electronic, up-to-date monitoring plan file for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii), no later than 21 days prior to the initial certification test; at the time of a certification or recertification application submission; and whenever an update of the electronic monitoring plan is required, either under § 75.53 or elsewhere in this part.
- (2) **Hardcopy submission.** The designated representative of an affected unit shall submit all of the hardcopy information required under § 75.53, for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii), to the permitting authority prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

(f) **Quarterly reports –**

- (1) **Electronic submission.** The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the information

provided in paragraphs (f)(1)(i) through (x) of this section and shall also include the date of report generation. A unit placed into long-term cold storage is exempted from submitting quarterly reports beginning with the calendar quarter following the quarter in which the unit is placed into long-term cold storage, provided that the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit).

(i) Facility information:

(A) Identification, including:

- (1) Facility/ORISPL number;
- (2) Calendar quarter and year data contained in the report; and
- (3) Electronic data reporting format version used for the report.

(B) [Reserved]

(ii) The information and hourly data required in paragraphs (a) and (b) of this section, except for:

- (A) Descriptions of adjustments, corrective action, and maintenance;
- (B) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
- (C) For units with NO_x add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);
- (D) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;
- (E) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;
- (F) Records of flow polynomial equations and numerical values required by § 75.59(a)(5)(vi);
- (G) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D to this part;
- (H) Information required by § 75.59(b)(2) concerning transmitter or transducer accuracy tests;
- (I) Stratification test results required as part of the RATA supplementary records under § 75.59(a)(7);
- (J) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to operational problems with the unit; and
- (K) Supplementary RATA information required under § 75.59(a)(7), except that:

- (1) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;
 - (2) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;
 - (3) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and
 - (4) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.
- (iii) Average NO_x emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_x emission rate for the calendar year.
 - (iv) Tons of NO_x emitted during quarter, cumulative tons of NO_x emitted during the year, and, during the second and third calendar quarters, cumulative tons of NO_x emitted during the ozone season.
 - (v) During the second and third calendar quarters, cumulative heat input for the ozone season.
 - (vi) Unit or stack or common pipe header operating hours for quarter, cumulative unit, stack or common pipe header operating hours for calendar year, and, during the second and third calendar quarters, cumulative operating hours during the ozone season.
 - (vii) Reporting period heat input.
 - (viii) New reporting frequency and begin date of the new reporting frequency (if applicable).
 - (ix) On and after on January 1, 2024, for a unit subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter and determining NO_x mass emission rate at a common stack, apportioned hourly NO_x mass emission rate for the unit, lb/hr.
 - (x) On and after January 1, 2024, for a unit that is subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter, that lists coal or a solid coal-derived fuel as a fuel in the unit's monitoring plan under § 75.53 for any portion of the ozone season in the year for which data are being reported, that serves a generator of 100 MW or larger nameplate capacity, and that is not a circulating fluidized bed boiler, provided that through December 31, 2029, the requirements under this paragraph (f)(1)(x) shall apply to a unit in a given calendar year only if the unit also was equipped with selective catalytic reduction controls on or before September 30 of the previous year:
 - (A) Daily NO_x emissions (lbs) for each day of the reporting period;
 - (B) Daily heat input (mmBtu) for each day of the reporting period;

- (C) Daily average NO_x emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;
 - (D) Daily NO_x emissions (lbs) exceeding the applicable backstop daily NO_x emission rate for each day of the reporting period;
 - (E) Cumulative NO_x emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_x emission rate during the ozone season; and
 - (F) Cumulative NO_x emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_x emission rate during the ozone season by more than 50 tons, calculated as the remainder of the amount calculated under paragraph (f)(1)(x)(E) of this section minus 50, but not less than zero.
- (2) **Verification of identification codes and formulas.** The designated representative shall certify that the component and system identification codes and formulas in the quarterly electronic reports submitted to the Administrator pursuant to paragraph (e) of this section represent current operating conditions.
- (3) **Compliance certification.** The designated representative shall submit and sign a compliance certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:
- (i) The monitoring data submitted were recorded in accordance with the applicable requirements of this part, including the quality assurance procedures and specifications; and
 - (ii) With regard to a unit with add-on emission controls and for all hours where data are substituted in accordance with § 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_x emissions.
- (4) **Electronic format, method of submission, and explanatory information.** The designated representative shall comply with all of the quarterly reporting requirements in § 75.64(d), (f), and (g).

[64 FR 28624, May 26, 1999, as amended at 67 FR 40446, June 12, 2002; 73 FR 4359, Jan. 24, 2008; 88 FR 36896, June 5, 2023]

§ 75.74 Annual and ozone season monitoring and reporting requirements.

- (a) **Annual monitoring requirement.**
- (1) The owner or operator of an affected unit subject both to an Acid Rain emission limitation and to a State or federal NO_x mass reduction program that adopts the provisions of this part must meet the requirements of this part during the entire calendar year.
 - (2) The owner or operator of an affected unit subject to a State or federal NO_x mass reduction program that adopts the provisions of this part and that requires monitoring and reporting of hourly emissions on an annual basis must meet the requirements of this part during the entire calendar year.
- (b) **Ozone season monitoring requirements.** The owner or operator of an affected unit that is not required to meet the requirements of this subpart on an annual basis under paragraph (a) of this section may either:
- (1) Meet the requirements of this subpart on an annual basis; or

- (2) Meet the requirements of this subpart during the ozone season, except as specified in paragraph (c) of this section.
- (c) If the owner or operator of an affected unit chooses to meet the requirements of this subpart on less than an annual basis in accordance with paragraph (b)(2) of this section, then:
 - (1) The owner or operator of a unit that uses continuous emissions monitoring systems or a fuel flowmeter to meet any of the requirements of this subpart shall quality assure the hourly ozone season emission data required by this subpart. To achieve this, the owner or operator shall operate, maintain and calibrate each required CEMS and shall perform diagnostic testing and quality assurance testing of each required CEMS or fuel flowmeter according to the applicable provisions of paragraphs (c)(2) through (c)(5) of this section. Except where otherwise noted, the provisions of paragraphs (c)(2) and (c)(3) of this section apply instead of the quality assurance provisions in sections 2.1 through 2.3 of appendix B to this part, and shall be used in lieu of those appendix B provisions.
 - (2) **Quality assurance requirements prior to the ozone season.** The provisions of this paragraph apply to each ozone season. The owner or operator shall, at a minimum, perform the following diagnostic testing and quality assurance assessments, and shall maintain the following records, to ensure that the hourly emission data recorded at the beginning of the current ozone season are suitable for reporting as quality-assured data:
 - (i) For each required gas monitor (i.e., for each NO_x pollutant concentration monitor and each diluent gas (CO₂ or O₂) monitor, including CO₂ and O₂ monitors used exclusively for heat input determination and O₂ monitors used for moisture determination), a linearity check shall be performed and passed in the second calendar quarter no later than April 30.
 - (A) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.
 - (B) Each linearity check shall be done "hands-off," as described in section 2.2.3(c) of appendix B to this part.
 - (C) In the time period extending from the date and hour in which the linearity check is passed through April 30, the owner or operator shall operate and maintain the CEMS and shall perform daily calibration error tests of the CEMS in accordance with section 2.1 of appendix B to this part. When a calibration error test is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions of section 2.1.3 of appendix B to this part shall be followed.
 - (D) If the linearity check is not completed by April 30, data validation shall be determined in accordance with paragraph (c)(3)(ii)(E) of this section.
 - (ii) For each required CEMS (i.e., for each NO_x concentration monitoring system, each NO_x-diluent monitoring system, each flow rate monitoring system, each moisture monitoring system and each diluent gas CEMS used exclusively for heat input determination), a relative accuracy test audit (RATA) shall be performed and passed in the first or second calendar quarter, but no later than April 30.

- (A) Conduct each RATA in accordance with the applicable procedures in sections 6.5 through 6.5.10 of appendix A to this part, except that the data validation procedures in sections 6.5(f)(1) through (f)(6) do not apply, and, for flow rate monitoring systems, the required RATA load level(s) (or operating level(s)) shall be as specified in this paragraph.
- (B) Each RATA shall be done “hands-off,” as described in section 2.3.2 (c) of appendix B to this part. The provisions in section 2.3.1.4 of appendix B to this part, pertaining to the number of allowable RATA attempts, shall apply.
- (C) For flow rate monitoring systems installed on peaking units or bypass stacks and for flow monitors exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part, a single-load (or single-level) RATA is required. For all other flow rate monitoring systems, a 2-load (or 2-level) RATA is required at the two most frequently-used load or operating levels (as defined under section 6.5.2.1 of appendix A to this part), with the following exceptions. Except for flow monitors exempted from 3-level RATA testing under section 6.5.2(e) of appendix A to this part, a 3-load flow RATA is required at least once every five years and is also required if the flow monitor polynomial coefficients or K factor(s) are changed prior to conducting the flow RATA required under this paragraph.
- (D) A bias test of each required NO_x concentration monitoring system, each NO_x-diluent monitoring system and each flow rate monitoring system shall be performed in accordance with section 7.6 of appendix A to this part. If the bias test is failed, a bias adjustment factor (BAF) shall be calculated for the monitoring system, as described in section 7.6.5 of appendix A to this part and shall be applied to the subsequent data recorded by the CEMS.
- (E) In the time period extending from the hour of completion of the required RATA through April 30, the owner or operator shall operate and maintain the CEMS by performing, at a minimum, the following activities:
 - (1) The owner or operator shall perform daily calibration error tests and (if applicable) daily flow monitor interference checks, according to section 2.1 of appendix B to this part. When a daily calibration error test or interference check is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions in section 2.1.3 of appendix B to this part shall be followed. Records of the required daily calibration error tests and interference checks shall be kept in a format suitable for inspection on a year-round basis.
 - (2) If the owner or operator makes a replacement, modification, or change in a certified monitoring system that significantly affects the ability of the system to accurately measure or record NO_x mass emissions or heat input or to meet the requirements of § 75.21 or appendix B to this part, the owner or operator shall recertify the monitoring system according to § 75.20(b).
- (F) **Data validation.** For each RATA that is performed by April 30, data validation shall be done according to sections 2.3.2(a)-(j) of appendix B to this part. However, if a required RATA is not completed by April 30, data from the monitoring system shall be invalid, beginning with the first unit operating hour on or after May 1. The owner or operator shall continue to invalidate all data from the CEMS until either:
 - (1) The required RATA of the CEMS has been performed and passed; or

- (2) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required RATA in accordance with the conditional data validation provisions and within the 720 unit or stack operating hour time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term “quality assurance” shall apply instead of the term “recertification.” However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.
- (3) **Quality assurance requirements within the ozone season.** The provisions of this paragraph apply to each ozone season. The owner or operator shall, at a minimum, perform the following quality assurance testing during the ozone season, i.e. in the time period extending from May 1 through September 30 of each calendar year:
 - (i) Daily calibration error tests and (if applicable) interference checks of each CEMS required by this subpart shall be performed in accordance with sections 2.1.1 and 2.1.2 of appendix B to this part. The applicable provisions in sections 2.1.3, 2.1.4 and 2.1.5 of appendix B to this part, pertaining, respectively, to additional calibration error tests and calibration adjustments, data validation, and quality assurance of data with respect to daily assessments, shall also apply.
 - (ii) For each gas monitor required by this subpart, linearity checks shall be performed in the second and third calendar quarters, as follows:
 - (A) For the second calendar quarter, the pre-ozone season linearity check required under paragraph (c)(2)(i) of this section shall be performed by April 30.
 - (B) For the third calendar quarter, a linearity check shall be performed and passed no later than July 30.
 - (C) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.
 - (D) Each linearity check shall be done “hands-off,” as described in section 2.2.3(c) of appendix B to this part.
 - (E) **Data Validation.** For second and third quarter linearity checks performed by the applicable deadline (i.e., April 30 or July 30), data validation shall be done in accordance with sections 2.2.3(a), (b), (c), (e), and (h) of Appendix B to this part. However, if a required linearity check for the second calendar quarter is not completed by April 30, or if a required linearity check for the third calendar quarter is not completed by July 30, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour on or after May 1 or July 31, respectively. The owner or operator shall continue to invalidate all data from the CEMS until either:
 - (1) The required linearity check of the CEMS has been performed and passed; or
 - (2) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required linearity check in accordance with the conditional data validation provisions and within the 168 unit or stack operating hour

time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term “quality assurance” shall apply instead of the term “recertification.” However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

- (F) A pre-season linearity check performed and passed in April satisfies the linearity check requirement for the second quarter.
- (G) The third quarter linearity check requirement in paragraph (c)(3)(ii)(B) of this section is waived if:
 - (1) Due to infrequent unit operation, the 168 operating hour conditional data validation period associated with a pre-season linearity check extends into the third quarter; and
 - (2) A linearity check is performed and passed within that conditional data validation period.
- (iii) For each flow monitoring system required by this subpart, except for flow monitors installed on non-load-based units that do not produce electrical or thermal output, flow-to-load ratio tests are required in the second and third calendar quarters, in accordance with section 2.2.5 of appendix B to this part. If the flow-to-load ratio test for the second calendar quarter is failed, the owner or operator shall follow the procedures in section 2.2.5(c)(8) of appendix B to this part. If the flow-to-load ratio test for the third calendar quarter is failed, data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless, prior to May 1 of the next calendar year, the owner or operator has either successfully implemented Option 1 in section 2.2.5.1 of appendix B to this part or Option 2 in section 2.2.5.2 of appendix B to this part, or unless a flow RATA has been performed and passed in accordance with paragraph (c)(2)(ii) of this section.
- (iv) For each differential pressure-type flow monitor used to meet the requirements of this subpart, quarterly leak checks are required in the second and third calendar quarters, in accordance with section 2.2.2 of appendix B to this part. For the second calendar quarter of the year, only the unit or stack operating hours in the months of May and June shall be used to determine whether the second calendar quarter is a QA operating quarter (as defined in § 72.2 of this chapter). Data validation for quarterly flow monitor leak checks shall be done in accordance with section 2.2.3(g) of appendix B to this part. If the leak check for the third calendar quarter is failed and a subsequent leak check is not passed by the end of the ozone season, then data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless a leak check is passed prior to May 1 of the next calendar year.
- (v) A fuel flow-to-load ratio test in section 2.1.7 of appendix D to this part shall be performed in the second and third calendar quarters if, for a unit using a fuel flowmeter to determine heat input under this subpart, the owner or operator has elected to use the fuel flow-to-load ratio test to extend the deadline for the next fuel flowmeter accuracy test. Automatic deadline extensions may be claimed for the two calendar quarters outside the ozone season (the first and fourth calendar quarters), since a fuel flow-to-load ratio test is not required in those quarters. If a fuel flow-to-load ratio test is failed, follow the applicable procedures and data validation provisions in section 2.1.7.4 of appendix D to this part. If the fuel flow-to-load ratio test for the third

calendar quarter is failed, data from the fuel flowmeter shall be considered invalid at the beginning of the next ozone season unless the requirements of section 2.1.7.4 of appendix D to this part have been fully met prior to May 1 of the next calendar year.

(vi)-(viii) [Reserved]

- (ix) If, for any required CEMS, diagnostic linearity checks or RATAs other than those required by this section are performed during the ozone season, use the applicable data validation procedures in section 2.2.3 (for linearity checks) or 2.3.2 (for RATAs) of appendix B to this part.
- (x) If any required CEMS is recertified within the ozone season, use the data validation provisions in § 75.20(b)(3) and, if applicable, paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.
- (xi) If, at the end of the second quarter of any calendar year, a required quality assurance, diagnostic, or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report for the second calendar quarter. The owner or operator shall resubmit the report for the second quarter if the required quality assurance, diagnostic, or recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in §§ 75.31 through § 75.37 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed quality assurance, diagnostic, or recertification test. Alternatively, if any required quality assurance, diagnostic, or recertification test is not completed by the end of the second calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under § 75.73), the test data and results may be submitted with the second quarter report even though the test date(s) are from the third calendar quarter. In such instances, if the quality assurance, diagnostic, or recertification test(s) are passed in accordance with the conditional data validation provisions of § 75.20(b)(3), conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the tests are failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required.
- (xii) If, at the end of the third quarter of any calendar year, a required quality assurance, diagnostic or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed, the owner or operator shall do one of the following:
 - (A) If the results of the required tests are not available within 30 days of the end of the third calendar quarter and cannot be submitted with the quarterly report for the third calendar quarter, then the test results are considered to be missing and the owner or operator shall use the appropriate missing data routine in §§ 75.31 through § 75.37 to replace with substitute data each hour of conditionally valid data in the third quarter report. In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same missing tests, the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in §§ 75.31 through § 75.37 to replace with substitute data each hour of conditionally valid data associated with the missing quality assurance, diagnostic, or recertification tests; or

- (B) If the required quality assurance, diagnostic, or recertification tests are completed no later than 30 days after the end of the third calendar quarter, the test data and results may be submitted with the third quarter report even though the test date(s) are from the fourth calendar quarter. In this instance, if the required tests are passed in accordance with the conditional data validation provisions of § 75.20(b)(3), all conditionally valid data associated with the tests shall be reported as quality-assured. If the tests are failed, the owner or operator shall use the appropriate missing data routine in §§ 75.31 through § 75.37 to replace with substitute data each hour of conditionally valid data associated with the failed test(s). In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same failed test(s), the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in §§ 75.31 through § 75.37 to replace with substitute data each hour of conditionally valid data associated with the failed test(s).
- (4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input rate is required to maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall include all fuel flowmeter QA operating quarters (as defined in § 72.2) for the entire calendar year, not just fuel flowmeter QA operating quarters in the ozone season. For each calendar year, the owner or operator shall record, for each fuel flowmeter, the number of fuel flowmeter QA operating quarters. The owner or operator shall include all calendar quarters in the year when determining the deadline for visual inspection of the primary fuel flowmeter element, as specified in section 2.1.6(c) of appendix D to this part.
- (5) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input rate is only required to sample fuel for the purposes of determining density and GCV during the ozone season, except that:
 - (i) The owner or operator of a unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.
 - (ii) The owner or operator of a unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.
 - (iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel or that performs fuel sampling continuously must sample the fuel starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.
- (6) The owner or operator shall, in accordance with § 75.73, record and report the hourly data required by this subpart and shall record and report the results of all required quality assurance tests, as follows:
 - (i) All hourly emission data for the period of time from May 1 through September 30 of each calendar year shall be recorded and reported. For missing data purposes, only the data recorded in the time period from May 1 through September 30 shall be considered quality-assured;

- (ii) The results of all daily calibration error tests and flow monitor interference checks performed in the time period from May 1 through September 30 shall be recorded and reported;
 - (iii) For the time periods described in paragraphs (c)(2)(i)(C) and (c)(2)(ii)(E) of this section, hourly emission data and the results of all daily calibration error tests and flow monitor interference checks shall be recorded. The owner or operator may opt to report unit operating data, daily calibration error test and flow monitor interference check results, and hourly emission data in the time period from April 1 through April 30. However, only the data recorded in the time period from May 1 through September 30 shall be used for NO_x mass compliance determination;
 - (iv) The results of all required quality assurance tests (RATAs, linearity checks, flow-to-load ratio tests and leak checks) performed during the ozone season shall be reported in the appropriate ozone season quarterly report; and
 - (v) The results of RATAs (and any other quality assurance test(s) required under paragraph (c)(2) or (c)(3) of this section) which affect data validation for the current ozone season, but which were performed outside the ozone season (i.e., between January 1 and April 30 of the current calendar year), shall be reported in the quarterly report for the second quarter of the current calendar year (or in the report for the third calendar quarter of the current calendar year, if the unit or stack does not operate in the second quarter).
- (7) The owner or operator shall use only quality-assured data from within ozone seasons in the substitute data procedures under subpart D of this part and section 2.4.2 of appendix D to this part.
- (i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_x-diluent continuous emission monitoring system, a NO_x concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only quality-assured data from periods within ozone seasons.
 - (ii) The applicable missing data procedures of §§ 75.31 through 75.37 shall be used, with one exception. When a fuel which has a significantly higher NO_x emission rate than any of the fuel(s) combusted in prior ozone seasons is combusted in the unit, and no quality-assured NO_x data have been recorded in the current, or any previous, ozone season while combusting the new fuel, the owner or operator shall substitute the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, from a NO_x-diluent continuous emission monitoring system, or the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, from a NO_x concentration monitoring system. The maximum potential value used shall be specific to the new fuel. The owner or operator shall substitute the maximum potential value for each hour of missing NO_x data until the first hour that quality-assured NO_x data are obtained while combusting the new fuel, and then shall resume use of the missing data routines in §§ 75.31 through 75.37; and
 - (iii) In order to apply the missing data routines described in §§ 75.31 through 75.37 on an ozone season-only basis, the procedures in those sections shall be modified as follows:
 - (A) The use of the initial missing data procedures in § 75.31 shall commence with the first unit operating hour in the first ozone season for which emissions data are required to be reported under § 75.64.

- (B) In § 75.31(a), the phrases “During the first 720 quality-assured monitor operating hours within the ozone season” and “during the first 2,160 quality-assured monitor operating hours within the ozone season” apply respectively instead of the phrases “During the first 720 quality-assured monitor operating hours” and “during the first 2,160 quality-assured monitor operating hours”.
- (C) In § 75.32(a), the phrases “the first 720 quality-assured monitor operating hours within the ozone season” and “the first 2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “the first 720 quality-assured monitor operating hours” and “the first 2,160 quality-assured monitor operating hours”.
- (D) In § 75.32(a)(1), the phrase “Following initial certification, prior to completion of 3,672 unit (or stack) operating hours within the ozone season” applies instead of the phrase “Prior to completion of 8,760 unit (or stack) operating hours following initial certification”.
- (E) In Equation 8, the phrase “Total unit operating hours within the ozone season” applies instead of the phrase “Total unit operating hours”.
- (F) In § 75.32(a)(2), the phrase “3,672 unit (or stack) operating hours within the ozone season” applies instead of the phrase “8,760 unit (or stack) operating hours”.
- (G) In the numerator of Equation 9, the phrase “Total unit operating hours within the ozone season” applies instead of the phrase “Total unit operating hours”, and the phrase “3,672 unit operating hours within the ozone season” applies instead of the phrase “8,760 unit operating hours”. In the denominator of Equation 9, the number “3,672” applies instead of “8,760”.
- (H) Use the following instead of the first three sentences in § 75.32(a)(3): “When calculating percent monitor data availability using Equation 8 or 9, the owner or operator shall include all unit or stack operating hours within the ozone season, and all monitor operating hours within the ozone season for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part. No hours from more than three years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated fewer than 3,672 ozone season operating hours in the previous three years, use the following: in the numerator of Equation 9 use ‘Total unit operating hours within the ozone season for which quality-assured data were recorded in the previous three years’; and in the denominator of Equation 9 use ‘Total unit operating hours within the ozone season, in the previous three years’ ”
- (I) In § 75.33(a), the phrases “the first 720 quality-assured monitor operating hours within the ozone season” and “the first 2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “the first 720 quality-assured monitor operating hours” and “the first 2,160 quality-assured monitor operating hours”.
- (J) Instead of the last sentence of § 75.33(a), use “For the purposes of missing data substitution, the owner or operator of a unit shall use only quality-assured monitor operating hours of data that were recorded within the ozone season and no more than three years (26,280 clock hours) prior to the date and time of the missing data period.”

- (K) In §§ 75.33(b), 75.33(c), 75.35, 75.36, and 75.37, the phrases “720 quality-assured monitor operating hours within the ozone season” and “2,160 quality-assured monitor operating hours within the ozone season” apply, respectively, instead of the phrases “720 quality-assured monitor operating hours” and “2,160 quality-assured monitor operating hours”.
 - (L) In § 75.34(a)(3) and (a)(5), the phrases “720 quality-assured monitor operating hours within the ozone season” and “2160 quality-assured monitor operating hours within the ozone season” apply instead of “720 quality-assured monitor operating hours” and “2160 quality-assured monitor operating hours”, respectively.
- (8) The owner or operator of a unit with NO_x add-on emission controls or a unit capable of combusting more than one fuel shall keep records during ozone season in a form suitable for inspection to demonstrate that the typical NO_x emission rate or NO_x concentration during the prior ozone season(s) included in the missing data lookback period is representative of the ozone season in which missing data are substituted and that use of the missing data procedures will not systematically underestimate NO_x mass emissions. These records shall include:
- (i) For units that can combust more than one fuel, the fuel or fuels combusted each hour; and
 - (ii) For units with add-on emission controls, using the missing data options in §§ 75.34(a)(1) through 75.34(a)(5), the range of operating parameters for add-on emission controls (as defined in the quality assurance/quality control program for the unit required by section 1 in appendix B to this part) and information for verifying proper operation of the add-on emission controls during missing data periods, as described in § 75.34(d).
- (9) The designated representative shall certify with each quarterly report that NO_x emission rate values or NO_x concentration values substituted for missing data under subpart D of this part are calculated using only values from an ozone season, that substitute values measured during the prior ozone season(s) included in the missing data lookback period are representative of the ozone season in which missing data are substituted, and that NO_x emissions are not systematically underestimated.
- (10) Units may qualify to use the low mass emissions excepted monitoring methodology in § 75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 50 tons of NO_x per ozone season, as provided in § 75.19(a)(1)(i)(A)(3). If any low mass emissions unit fails to provide a demonstration that its ozone season NO_x mass emissions are less than or equal to 50 tons, then the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitored using an acceptable methodology by December 31 of the following year.
- (11) Units may qualify to use the optional NO_x mass emissions estimation protocol for gas-fired and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of “peaking unit” in § 72.2 of this chapter, except that the words “year”, “calendar year” and “calendar years” in that definition shall be replaced by the words “ozone season”, “ozone season”, and “ozone seasons”, respectively. In addition, in the definition of the term “capacity factor” in § 72.2 of this chapter, the word “annual” shall be replaced by the words “ozone season” and the number “8,760” shall be replaced by the number “3,672”.

[63 FR 57507, Oct. 27, 1998, as amended at 64 FR 28627, May 26, 1999; 67 FR 40446, 40447, June 12, 2002; 67 FR 57274, Sept. 9, 2002; 73 FR 4360, Jan. 24, 2008]

§ 75.75 Additional ozone season calculation procedures.

- (a) The owner or operator of a unit that is required to calculate daily or ozone season heat input shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the day or ozone season.
- (b) The owner or operator of a unit that is required to determine daily or ozone season NO_x emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO_x mass emissions (in lbs) determined in accordance with this subpart, by daily or ozone season heat input determined in accordance with paragraph (a) of this section.

[88 FR 36896, June 5, 2023]

Appendix A to Part 75—Specifications and Test Procedures

1. Installation and Measurement Location

1.1 Gas Monitors

- (a) Following the procedures in section 8.1.1 of Performance Specification 2 in appendix B to part 60 of this chapter, install the pollutant concentration monitor or monitoring system at a location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO₂, CO₂, O₂, or NO_x concentration monitoring system or NO_x-diluent CEMS (NO_x pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see section 6 of this appendix).
- (b) It is recommended that monitor measurements be made at locations where the exhaust gas temperature is above the dew-point temperature. If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, relocate the monitor probe(s).

1.1.1 Point Monitors

Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.2 Path Monitors

Locate the measurement path (1) totally within the inner area bounded by a line 1.0 meter from the stack or duct wall, or (2) such that at least 70.0 percent of the path is within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) such that the path is centrally located within any part of the centroidal area.

1.2 Flow Monitors

Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO₂ emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of appendix A to part 60 of this chapter to establish a proper location for the flow monitor. The EPA recommends (but does not require) performing a flow profile study following the procedures in 40 CFR part 60, appendix A, method, 1, sections 11.5 or 11.4 for each of the three operating or load levels indicated in section 6.5.2.1 of this appendix to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, appendix A, Test Method 1, section 11.5 may be used even if the flow measurement location is greater than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to $\frac{1}{2}$ duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this part, then EPA recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. EPA also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.2.1 Acceptability of Monitor Location

The installation of a flow monitor is acceptable if either (1) the location satisfies the minimum siting criteria of method 1 in appendix A to part 60 of this chapter (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from a flow disturbance), or (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions), and the flow monitor also satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the location is acceptable, notwithstanding the requirements of this section.

1.2.2 Alternative Monitoring Location

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.2.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Administrator for an alternative method for monitoring flow.

2. Equipment Specifications

2.1 Instrument Span and Range

In implementing sections 2.1.1 through 2.1.6 of this appendix, set the measurement range for each parameter (SO₂, NO_x, CO₂, O₂, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise ratio. To meet these objectives, select the range such that the majority of the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of the full-scale range of the instrument. These guidelines do not apply to: (1) SO₂ readings obtained during the combustion of very low sulfur fuel (as defined in § 72.2 of this chapter); (2) SO₂ or NO_x readings recorded on the high measurement range, for units with SO₂ or NO_x emission controls and two span values, unless the emission controls are operated seasonally (for example, only during the ozone season); or (3) SO₂ or NO_x readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit, provided that the maximum expected concentration (MEC), low-scale span value, and low-scale range settings have been determined according to sections 2.1.1.2, 2.1.1.4(a), (b), and (g) of this appendix (for SO₂), or according to sections 2.1.2.2, 2.1.2.4(a) and (f) of this appendix (for NO_x).

2.1.1 SO₂ Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.1.1 through 2.1.1.5 of this appendix the span value(s) and range(s) for an SO₂ pollutant concentration monitor so that all potential and expected concentrations can be accurately measured and recorded. Note that if a unit exclusively combusts fuels that are very low sulfur fuels (as defined in § 72.2 of this chapter), the SO₂ monitor span requirements in § 75.11(e)(3)(iv) apply in lieu of the requirements of this section.

2.1.1.1 Maximum Potential Concentration

- (a) Make an initial determination of the maximum potential concentration (MPC) of SO₂ by using Equation A-1a or A-1b. Base the MPC calculation on the maximum percent sulfur and the minimum gross calorific value (GCV) for the highest-sulfur fuel to be burned. The maximum sulfur content and minimum GCV shall be determined from all available fuel sampling and analysis data for that fuel from the previous 12 months (minimum), excluding clearly anomalous fuel sampling values. If both the fuel sulfur content and the GCV are routinely determined from each fuel sample, the owner or operator may, as an alternative to using the highest individual percent sulfur and lowest individual GCV values in the MPC calculation, pair the sulfur content and GCV values from each sample analysis and calculate the ratio of percent sulfur to GCV (i.e., %S/GCV) for each pair of values. If this option is selected, the MPC shall be calculated using the highest %S/GCV ratio in Equation A-1a or A-1b. If the designated

representative certifies that the highest-sulfur fuel is never burned alone in the unit during normal operation but is always blended or co-fired with other fuel(s), the MPC may be calculated using a best estimate of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A-1a or A-1b. Derive the best estimate of the highest percent sulfur and lowest GCV for a blend or fuel mixture from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months. If insufficient representative fuel sampling data are available to determine the maximum sulfur content and minimum GCV, use values from contract(s) for the fuel(s) that will be combusted by the unit in the MPC calculation.

$$\text{MPC (or MEC)} = 11.32 \times 10^6 \left(\frac{\%S}{\text{GCV}} \right) \left(\frac{20.9 - \%O_{2w}}{20.9} \right) \quad (\text{Eq. A-1a})$$

or

$$\text{MPC (or MEC)} = 66.93 \times 10^6 \left(\frac{\%S}{\text{GCV}} \right) \left(\frac{\%CO_{2w}}{100} \right) \quad (\text{Eq. A - 1b})$$

Where,

MPC = Maximum potential concentration (ppm, wet basis). (To convert to dry basis, divide the MPC by 0.9.)

MEC = Maximum expected concentration (ppm, wet basis). (To convert to dry basis, divide the MEC by 0.9).

%S = Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined according to the applicable method in paragraph (c) of section 2.1.1.1.

%O_{2w} = Minimum oxygen concentration, percent wet basis, under typical operating conditions.

%CO_{2w} = Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.

GCV = Minimum gross calorific value of the fuel or blend to be combusted, based on historical fuel sampling and analysis data or, if applicable, based on the fuel contract specifications (Btu/lb). If based on fuel sampling and analysis, the GCV shall be determined according to the applicable method in paragraph (c) of section 2.1.1.1.

11.32×10^6 = Oxygen-based conversion factor in Btu/lb (ppm)/%.

66.93×10^6 = Carbon dioxide-based conversion factor in Btu/lb (ppm)/%.

Note: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value (e.g., 3, not .03).

- (b) Alternatively, if a certified SO₂ CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality-assured historical data recorded by the CEMS. For the purposes of this section, 2.1.1.1, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen, the MPC shall be the maximum SO₂ concentration observed during the previous 720 (or more) quality-assured monitor operating hours when combusting the highest-sulfur fuel (or highest-sulfur blend if fuels are always blended or co-fired) that is to be combusted in the unit or units monitored by the SO₂ monitor. For units with SO₂ emission controls, the certified SO₂ monitor used to determine the MPC must be located at or before the control device inlet. Report the MPC and the method of determination in the monitoring plan required under § 75.53. Note that the initial MPC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.
- (c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D129-00, ASTM D240-00, ASTM D1552-01, ASTM D2622-98, ASTM D3176-89 (Reapproved 2002), ASTM D3177-02 (Reapproved 2007), ASTM D4239-02, ASTM D4294-98, ASTM D5865-01a, or ASTM D5865-10 (all incorporated by reference under § 75.6).

2.1.1.2 Maximum Expected Concentration

- (a) Make an initial determination of the maximum expected concentration (MEC) of SO₂ whenever: (a) SO₂ emission controls are used; or (b) both high-sulfur and low-sulfur fuels (e.g., high-sulfur coal and low-sulfur coal or different grades of fuel oil) or high-sulfur and low-sulfur fuel blends are combusted as primary or backup fuels in a unit without SO₂ emission controls. For units with SO₂ emission controls, use Equation A-2 to make the initial MEC determination. When high-sulfur and low-sulfur fuels or blends are burned as primary or backup fuels in a unit without SO₂ controls, use Equation A-1a or A-1b to calculate the initial MEC value for each fuel or blend, except for: (1) the highest-sulfur fuel or blend (for which the MPC was previously calculated in section 2.1.1.1 of this appendix); (2) fuels or blends that are very low sulfur fuels (as defined in § 72.2 of this chapter); or (3) fuels or blends that are used only for unit startup. Each initial MEC value shall be documented in the monitoring plan required under § 75.53. Note that each initial MEC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.
- (b) For each MEC determination, substitute into Equation A-1a or A-1b the highest sulfur content and minimum GCV value for that fuel or blend, based upon all available fuel sampling and analysis results from the previous 12 months (or more), or, if fuel sampling data are unavailable, based upon fuel contract(s).

- (c) Alternatively, if a certified SO₂ CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. For the purposes of this section, 2.1.1.2, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit. If this option is chosen for a unit with SO₂ emission controls, the MEC shall be the maximum SO₂ concentration measured downstream of the control device outlet by the CEMS over the previous 720 (or more) quality-assured monitor operating hours with the unit and the control device both operating normally. For units that burn high- and low-sulfur fuels or blends as primary and backup fuels and have no SO₂ emission controls, the MEC for each fuel shall be the maximum SO₂ concentration measured by the CEMS over the previous 720 (or more) quality-assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

$$MEC = MPC \left(\frac{100 - RE}{100} \right) \quad (\text{Eq. A-2})$$

Where:

MEC = Maximum expected concentration (ppm).

MPC = Maximum potential concentration (ppm), as determined by Eq. A-1a or A-1b in section 2.1.1.1 of this appendix.

RE = Expected average design removal efficiency of control equipment (%).

2.1.1.3 Span Value(s) and Range(s)

Determine the high span value and the high full-scale range of the SO₂ monitor as follows. (Note: For purposes of this part, the high span and range refer, respectively, either to the span and range of a single span unit or to the high span and range of a dual span unit.) The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the SO₂ span concentration is ≤500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine concentrations of the calibration gases required for daily calibration error checks and linearity tests. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Report the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit. Note that for certain applications, a second (low) SO₂ span and range may be required (see section 2.1.1.4 of this appendix). If an existing State, local, or federal requirement for span of an SO₂ pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.1.4 of this appendix, the State, local, or federal span value may be used if a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix. Span values higher than those required by either this section or section 2.1.1.4 of this appendix must be approved by the Administrator.

2.1.1.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.1.3 of this appendix will suffice to measure and record SO₂ concentrations (unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all possible or expected SO₂ concentrations. To determine whether two SO₂ span values are required, proceed as follows:

- (a) For units with SO₂ emission controls, compare the MEC from section 2.1.1.2 of this appendix to the high full-scale range value from section 2.1.1.3 of this appendix. If the MEC is ≥ 20.0 percent of the high range value, then the high span value and range determined under section 2.1.1.3 of this appendix are sufficient. If the MEC is < 20.0 percent of the high range value, then a second (low) span value is required.
- (b) For units that combust high- and low-sulfur primary and backup fuels (or blends) and have no SO₂ controls, compare the high range value from section 2.1.1.3 of this appendix (for the highest-sulfur fuel or blend) to the MEC value for each of the other fuels or blends, as determined under section 2.1.1.2 of this appendix. If all of the MEC values are ≥ 20.0 percent of the high range value, the high span and range determined under section 2.1.1.3 of this appendix are sufficient, regardless of which fuel or blend is burned in the unit. If any MEC value is < 20.0 percent of the high range value, then a second (low) span value must be used when that fuel or blend is combusted.
- (c) When two SO₂ spans are required, the owner or operator may either use a single SO₂ analyzer with a dual range (i.e., low- and high-scales) or two separate SO₂ analyzers connected to a common sample probe and sample interface. Alternatively, if RATAs are performed and passed on both measurement ranges, the owner or operator may use two separate SO₂ analyzers connected to separate probes and sample interfaces. For units with SO₂ emission controls, the owner or operator may use a low range analyzer and a default high range value, as described in paragraph (f) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.
- (d) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: when a single probe and sample interface are used, either designate the low and high monitor ranges as separate SO₂ components of a single, primary SO₂ monitoring system; designate the low and high monitor ranges as the SO₂ components of two separate, primary SO₂ monitoring systems; designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or, when a single, dual-range SO₂ analyzer is used, designate the low and high ranges as a single SO₂ component of a primary SO₂ monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two SO₂ analyzers are connected to separate probes and sample interfaces, designate the analyzers as the SO₂ components of two separate, primary SO₂ monitoring systems. For units with

SO₂ controls, if the default high range value is used, designate the low range analyzer as the SO₂ component of a primary SO₂ monitoring system. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

- (e) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) or § 75.20(d)(1), as applicable, and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for units with SO₂ emission controls, the low range is considered normal). Each monitoring system designated as a non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).
- (f) For dual span units with SO₂ emission controls, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default SO₂ concentration of 200 percent of the MPC for each unit operating hour in which the full-scale of the low range SO₂ analyzer is exceeded.
- (g) The high span value and range shall be determined in accordance with section 2.1.1.3 of this appendix. The low span value shall be obtained by multiplying the MEC by a factor no less than 1.00 and no greater than 1.25, and rounding the result upward to the next highest multiple of 10 ppm (or 100 ppm, as appropriate). For units that burn high- and low-sulfur primary and backup fuels or blends and have no SO₂ emission controls, select, as the basis for calculating the appropriate low span value and range, the fuel-specific MEC value closest to 20.0 percent of the high full-scale range value (from paragraph (b) of this section). The low range must be greater than or equal to the low span value, and the required calibration gases must be selected based on the low span value. However, if the default high range option in paragraph (f) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two SO₂ spans, use the low range whenever the SO₂ concentrations are expected to be consistently below 20.0 percent of the high full-scale range value, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the high full-scale range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the SO₂ concentrations; or, if applicable, the default high range value in paragraph (f) of this section shall be reported for each hour of the full-scale exceedance.

2.1.1.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each SO₂ monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a), (b), and (c) of this section. Span and range adjustments may be required, for example, as a

result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, SO₂ data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

- (a) If the fuel supply, the composition of the fuel blend(s), the emission controls, or the manner of operation change such that the maximum expected or potential concentration changes significantly, adjust the span and range setting to assure the continued accuracy of the monitoring system. A "significant" change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the concentration of emissions being emitted from the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Determine the adjusted span(s) using the procedures in sections 2.1.1.3 and 2.1.1.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the new span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.
- (b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:
 - (1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly SO₂ concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.
 - (2) For units with two SO₂ spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO₂ concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

- (c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO₂ monitor, as described in paragraphs (a) or (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

2.1.2 NO_x Pollutant Concentration Monitors

Determine, as indicated in sections 2.1.2.1 through 2.1.2.5 of this appendix, the span and range value(s) for the NO_x pollutant concentration monitor so that all expected NO_x concentrations can be determined and recorded accurately.

2.1.2.1 Maximum Potential Concentration

- (a) The maximum potential concentration (MPC) of NO_x for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO_x emissions. For the purposes of this section, 2.1.2.1, and section 2.1.2.2 of this appendix, a “blend” means a frequently-used fuel mixture having a consistent composition (e.g., an oil and gas mixture where the relative proportions of the two fuels vary by no more than 10%, on average). Make an initial determination of the MPC using the appropriate option as follows:

Option 1: Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_x (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil- or gas-fired units was previously selected under this section, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met); For cement kilns, use 2000 ppm as the MPC. For process heaters, use 200 ppm if the unit burns only gaseous fuel and 500 ppm if the unit burns oil;

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2-1 or Table 2-2; For a new gas-fired or oil-fired combustion turbine, if a default MPC value of 50 ppm was previously selected from Table 2-2, that value may be used until March 31, 2003;

Option 3: Use NO_x emission test results;

Option 4: Use historical CEM data over the previous 720 (or more) unit operating hours when combusting the fuel or blend with the highest NO_x emission rate; or

Option 5: If a reliable estimate of the uncontrolled NO_x emissions from the unit is available from the manufacturer, the estimated value may be used.

- (b) For the purpose of providing substitute data during NO_x missing data periods in accordance with §§ 75.31 and 75.33 and as required elsewhere under this part, the owner or operator shall also calculate the maximum potential NO_x emission rate (MER), in lb/mmBtu, by substituting the MPC for NO_x in conjunction with the minimum expected CO₂ or maximum O₂ concentration (under all unit operating conditions except for unit startup, shutdown, and upsets) and the appropriate F-factor into the applicable equation in appendix F to this part. The diluent cap value of 5.0 percent CO₂ (or 14.0 percent O₂) for boilers or 1.0 percent CO₂ (or 19.0 percent O₂) for combustion turbines may be used in the NO_x MER calculation. As a second alternative, when the NO_x MPC is determined from emission test results or from historical CEM data, as described in paragraphs (a), (d) and (e) of this section, quality-assured diluent gas (i.e., O₂ or CO₂) data recorded concurrently with the MPC may be used to calculate the MER.
- (c) Report the method of determining the initial MPC and the calculation of the maximum potential NO_x emission rate in the monitoring plan for the unit. Note that whichever MPC option in paragraph 2.1.2.1(a) of this appendix is selected, the initial MPC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.
- (d) For units with add-on NO_x controls (whether or not the unit is equipped with low-NO_x burner technology), or for units equipped with dry low-NO_x (DLN) technology, NO_x emission testing may only be used to determine the MPC if testing can be performed either upstream of the add-on controls or during a time or season when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_x) mode. If NO_x emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO_x concentration. (Note: Method 20 from appendix A to part 60 may be used for gas turbines, instead of Method 7E.) Operate the unit, or group of units sharing a common stack, at the minimum safe and stable load, the normal load, and the maximum load. If the normal load and maximum load are identical, an intermediate level need not be tested. Operate at the highest excess O₂ level expected under normal operating conditions. Make at least three runs of 20 minutes (minimum) duration with three traverse points per run at each operating condition. Select the highest point NO_x concentration from all test runs as the MPC for NO_x.
- (e) If historical CEM data are used to determine the MPC, the data must, for uncontrolled units or units equipped with low-NO_x burner technology and no other NO_x controls, represent a minimum of 720 quality-assured monitor operating hours from the NO_x component of a certified monitoring system, obtained under various operating conditions including the minimum safe and stable load, normal load (including periods of high excess air at normal load), and maximum load. For the purposes of this section, 2.1.2.1, a "certified" CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. For a unit with add-on NO_x controls (whether or not the unit is equipped with low-NO_x burner technology), or for a unit equipped with dry low-NO_x (DLN) technology, historical CEM data may only be

used to determine the MPC if the 720 quality-assured monitor operating hours of CEM data are collected upstream of the add-on controls or if the 720 hours of data include periods when the add-on controls are not in operation or when the DLN controls are not in the premixed (low-NO_x mode). For units that do not produce electrical or thermal output, the data must represent the full range of normal process operation. The highest hourly NO_x concentration in ppm shall be the MPC.

TABLE 2-1—MAXIMUM POTENTIAL CONCENTRATION FOR NO_x—COAL-FIRED UNITS

Unit type	Maximum potential concentration for NO _x (ppm)
Tangentially-fired dry bottom and fluidized bed	460
Wall-fired dry bottom, turbo-fired dry bottom, stokers	675
Roof-fired (vertically-fired) dry bottom, cell burners, arch-fired	975
Cyclone, wall-fired wet bottom, wet bottom turbo-fired	1200
Others	(¹)

¹ As approved by the Administrator.

**TABLE 2-2. -- MAXIMUM POTENTIAL CONCENTRATION FOR NO_x --
Gas- And Oil-Fired Units**

Unit type	Maximum potential concentration for NO _x (ppm)
Tangentially-fired dry bottom	380
Wall-fired dry bottom	600
Roof-fired (vertically-fired) dry bottom, arch-fired	550
Existing combustion turbine	200
New combustion turbine, permitted to fire either oil or natural gas	200
New combustion turbine, permitted to fire only natural gas	150
Others	(¹)

¹ As approved by the Administrator

2.1.2.2 Maximum Expected Concentration

- (a) Make an initial determination of the maximum expected concentration (MEC) of NO_x during normal operation for affected units with add-on NO_x controls of any kind (e.g., steam injection, water injection, SCR, or SNCR) and for turbines that use dry low-NO_x technology. Determine a separate MEC value for each type of fuel (or blend) combusted in the unit, except for fuels that are only used for unit startup and/or

flame stabilization. Calculate the MEC of NO_x using Equation A-2, if applicable, inserting the maximum potential concentration, as determined using the procedures in section 2.1.2.1 of this appendix. Where Equation A-2 is not applicable, set the MEC either by:

- (1) measuring the NO_x concentration using the testing procedures in this section;
 - (2) using historical CEM data over the previous 720 (or more) quality-assured monitor operating hours; or
 - (3) if the unit has add-on NO_x controls or uses dry low NO_x technology, and has a federally-enforceable permit limit for NO_x concentration, the permit limit may be used as the MEC. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined. Note that each initial MEC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.
- (b) If NO_x emission testing is used to determine the MEC value(s), the MEC for each type of fuel (or blend) shall be based upon testing at minimum load, normal load, and maximum load. At least three tests of 20 minutes (minimum) duration, using at least three traverse points, shall be performed at each load, using Method 7E from appendix A to part 60 of this chapter (Note: Method 20 from appendix A to part 60 may be used for gas turbines instead of Method 7E). The test must be performed at a time when all NO_x control devices and methods used to reduce NO_x emissions (if applicable) are operating properly. The testing shall be conducted downstream of all NO_x controls. The highest point NO_x concentration (e.g., the highest one-minute average) recorded during any of the test runs shall be the MEC.
- (c) If historical CEM data are used to determine the MEC value(s), the MEC for each type of fuel shall be based upon 720 (or more) hours of quality-assured data from the NO_x component of a certified monitoring system representing the entire load range under stable operating conditions. For the purposes of this section, 2.1.2.2, a “certified” CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or (for units with add-on NO_x controls or turbines using dry low NO_x technology) during any NO_x control device malfunctions or outages. All NO_x control devices and methods used to reduce NO_x emissions (if applicable) must be operating properly during each hour. The CEM data shall be collected downstream of all NO_x controls. For each type of fuel, the highest of the 720 (or more) quality-assured hourly average NO_x concentrations recorded by the CEMS shall be the MEC.

2.1.2.3 Span Value(s) and Range(s)

- (a) Determine the high span value of the NO_x monitor as follows. The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If

the NO_x span concentration is ≤500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. The high span value shall be used to determine the concentrations of the calibration gases required for daily calibration error checks and linearity tests. Note that for certain applications, a second (low) NO_x span and range may be required (see section 2.1.2.4 of this appendix).

- (b) If an existing State, local, or federal requirement for span of a NO_x pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.2.4 of this appendix, the State, local, or federal span value may be used, where a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.2.5 of this appendix. Span values higher than required by this section or by section 2.1.2.4 of this appendix must be approved by the Administrator.
- (c) Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the high span value. Include the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit.

2.1.2.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.2.3 of this appendix will suffice to measure and record NO_x concentrations (unless span and/or range adjustments must be made in accordance with section 2.1.2.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all expected and potential NO_x concentrations. To determine whether two NO_x spans are required, proceed as follows:

- (a) Compare the MEC value(s) determined in section 2.1.2.2 of this appendix to the high full-scale range value determined in section 2.1.2.3 of this appendix. If the MEC values for all fuels (or blends) are ≥20.0 percent of the high range value, the high span and range values determined under section 2.1.2.3 of this appendix are sufficient, irrespective of which fuel or blend is combusted in the unit. If any of the MEC values is <20.0 percent of the high range value, two spans (low and high) are required, one based on the MPC and the other based on the MEC.
- (b) When two NO_x spans are required, the owner or operator may either use a single NO_x analyzer with a dual range (low-and high-scales) or two separate NO_x analyzers connected to a common sample probe and sample interface. Two separate NO_x analyzers connected to separate probes and sample interfaces may be used if RATAs are passed on both ranges. For units with add-on NO_x emission controls (e.g., steam injection, water injection, SCR, or SNCR) or units equipped with dry low-NO_x technology, the owner or operator may use a low range analyzer and a “default high range value,” as described in paragraph 2.1.2.4(e) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

- (c) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: when a single probe and sample interface are used, either designate the low and high ranges as separate NO_x components of a single, primary NO_x monitoring system; designate the low and high ranges as the NO_x components of two separate, primary NO_x monitoring systems; designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or, when a single, dual-range NO_x analyzer is used, designate the low and high ranges as a single NO_x component of a primary NO_x monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two NO_x analyzers are connected to separate probes and sample interfaces, designate the analyzers as the NO_x components of two separate, primary NO_x monitoring systems. For units with add-on NO_x controls or units equipped with dry low-NO_x technology, if the default high range value is used, designate the low range analyzer as the NO_x component of the primary NO_x monitoring system. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.
- (d) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements in § 75.20(c) (for primary monitoring systems), in § 75.20(d)(1) (for redundant backup monitoring systems) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for dual span units with add-on NO_x emission controls, the low range is considered normal). Each monitoring system designated as non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).
- (e) For dual span units with add-on NO_x emission controls (e.g., steam injection, water injection, SCR, or SNCR), or, for units that use dry low NO_x technology, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default value of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range NO_x analyzer is exceeded.
- (f) The high span and range shall be determined in accordance with section 2.1.2.3 of this appendix. The low span value shall be 100.0 to 125.0 percent of the MEC, rounded up to the next highest multiple of 10 ppm (or 100 ppm, if appropriate). If more than one MEC value (as determined in section 2.1.2.2 of this appendix) is <20.0 percent of the high full-scale range value, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the high range value. The low range must be greater than or equal to the low span value, and the required calibration gases for the low range must be selected based on the low span value. However, if the default high range option in paragraph (e) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). For units with two NO_x spans, use the low range whenever NO_x concentrations are expected to be consistently <20.0 percent of the high range value, i.e., when the MEC

of the fuel being combusted is <20.0 percent of the high range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the NO_x concentrations; or, if applicable, the default high range value in paragraph (e) of this section shall be reported for each hour of the full-scale exceedance.

2.1.2.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each NO_x monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a), (b), and (c) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, note that NO_x data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

- (a) If the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration changes significantly, adjust the NO_x pollutant concentration span(s) and (if necessary) monitor range(s) to assure the continued accuracy of the monitoring system. A "significant" change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit or stack may affect the concentration of emissions being emitted from the unit and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. An example of a change that may require a span and range adjustment is the installation of low-NO_x burner technology on a previously uncontrolled unit. Determine the adjusted span(s) using the procedures in section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the adjusted span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.
- (b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

- (1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly NO_x concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.
- (2) For units with two NO_x spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_x concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).
- (c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_x monitor as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC, maximum potential NO_x emission rate, and the adjusted span value in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check required by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is significant enough that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, a diagnostic linearity test using the new calibration gases must be performed and passed. Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

2.1.3 CO₂ and O₂ Monitors

For an O₂ monitor (including O₂ monitors used to measure CO₂ emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O₂. For a CO₂ monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO₂. For a CO₂ monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO₂ may be used. An alternative CO₂ span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan. An alternative O₂ span value below 15.0 percent O₂ may be used if an appropriate technical justification is included in the monitoring plan (e.g., O₂ concentrations above a certain level create an unsafe operating condition). Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with section 5.1 of this appendix, as percentages of the span value. For O₂ monitors with span values ≥21.0 percent O₂, purified instrument air containing 20.9 percent O₂ may be used as the

high-level calibration material. If a dual-range or autoranging diluent analyzer is installed, the analyzer may be represented in the monitoring plan as a single component, using a special component type code specified by the Administrator to satisfy the requirements of § 75.53(e)(1)(iv)(D).

2.1.3.1 Maximum Potential Concentration of CO₂

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO₂ and NO_x monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary.

For CO₂ pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO₂ for boilers and 6.0 percent CO₂ for combustion turbines. Alternatively, the owner or operator may determine the MPC based on a minimum of 720 hours of quality-assured historical CEM data representing the full operating load range of the unit(s). Note that the MPC for CO₂ monitors shall only be used for the purpose of providing substitute data under this part. The CO₂ monitor span and range shall be determined according to section 2.1.3 of this appendix.

2.1.3.2 Minimum Potential Concentration of O₂

The owner or operator of a unit that uses a flow monitor and an O₂ diluent monitor to determine heat input in accordance with Equation F-17 or F-18 in appendix F to this part shall, for the purposes of providing substitute data under § 75.36, determine the minimum potential O₂ concentration. The minimum potential O₂ concentration shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The minimum potential O₂ concentration shall be the lowest quality-assured hourly average O₂ concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.3.3 Adjustment of Span and Range

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO₂ and NO_x monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary. Adjust the span value and range of a CO₂ or O₂ monitor in accordance with section 2.1.1.5 of this appendix (insofar as those provisions are applicable), with the term "CO₂ or O₂" applying instead of the term "SO₂". Set the new span and range in accordance with section 2.1.3 of this appendix and report the new span value in the monitoring plan.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix and can accurately measure all potential volumetric flow rates at the flow monitor installation site.

2.1.4.1 Maximum Potential Velocity and Flow Rate

For this purpose, determine the span value of the flow monitor using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A-3a or A-3b or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load (or, for units that do not produce electrical or thermal output, at the normal process operating conditions corresponding to the maximum stack gas flow rate). Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with §§ 75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft²) at the flow monitor location.

$$MPV = \left(\frac{F_d H_f}{A} \right) \left(\frac{20.9}{20.9 - \%O_{2d}} \right) \left(\frac{100}{100 - \%H_2O} \right) \quad (\text{Eq. A-3a})$$

or

$$MPV = \left(\frac{F_c H_f}{A} \right) \left(\frac{100}{\%CO_{2d}} \right) \left(\frac{100}{100 - \%H_2O} \right) \quad (\text{Eq. A-3b})$$

Where:

MPV = maximum potential velocity (fpm, standard wet basis).

F_d = dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F to this part.

F_c = carbon-based F factor (scf CO₂/mmBtu) from Table 1, Appendix F to this part.

H_f = maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located.

A = inside cross sectional area (ft²) of the flue at the flow monitor location.

%O_{2d} = maximum oxygen concentration, percent dry basis, under normal operating conditions.

%CO_{2d} = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.

%H₂O = maximum percent flue gas moisture content under normal operating conditions.

2.1.4.2 Span Values and Range

Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in section 2.1.4.1 of this appendix, to the same measurement units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the “calibration span value” by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least two significant figures. For calibration span values in inches of water, retain at least two decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value, as specified in section 2.2.2.1 of this appendix. Finally, calculate the “flow rate span value” (in scfh) as the product of the MPF, as determined in section 2.1.4.1 of this appendix, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the span value and is consistent with section 2.1 of this appendix. Include in the monitoring plan for the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-scale range (expressed both in scfh and, if different, in the measurement units of calibration).

2.1.4.3 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPV, MPF, span, and range values for each flow rate monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments with corresponding monitoring plan updates, as described in paragraphs (a) through (c) of this section 2.1.4.3. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the stack or ductwork configuration, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section 2.1.4.3, note that flow rate data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified.

- (a) If the fuel supply, stack or ductwork configuration, operating parameters, or other conditions change such that the maximum potential flow rate changes significantly, adjust the span and range to assure the continued accuracy of the flow monitor. A “significant” change in the MPV or MPF means that the guidelines of section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the flow of the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as

timely a manner as practicable to coordinate with the operational changes. Calculate the adjusted calibration span and flow rate span values using the procedures in section 2.1.4.2 of this appendix.

- (b) Whenever the full-scale range is exceeded during a quarter, provided that the exceedance is not caused by a monitor out-of-control period, report 200.0 percent of the current full-scale range as the hourly flow rate for each hour of the full-scale exceedance. If the range is exceeded, make appropriate adjustments to the MPF, flow rate span, and range to prevent future full-scale exceedances. Calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. A calibration error test must be performed and passed to validate data on the new range.
- (c) Whenever changes are made to the MPV, MPF, full-scale range, or span value of the flow monitor, as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, calculations of the flow rate span value, calibration span value, MPV, and MPF in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. Record and report the adjusted calibration span and reference values as parts of the records for the calibration error test required by appendix B to this part. Whenever the calibration span value is adjusted, use reference values for the calibration error test that meet the requirements of section 2.2.2.1 of this appendix, based on the most recent adjusted calibration span value. Perform a calibration error test according to section 2.1.1 of appendix B to this part whenever making a change to the flow monitor span or range, unless the range change also triggers a recertification under § 75.20(b).

2.1.5 Minimum Potential Moisture Percentage

Except as provided in section 2.1.6 of this appendix, the owner or operator of a unit that uses a continuous moisture monitoring system to correct emission rates and heat inputs from a dry basis to a wet basis (or vice-versa) shall, for the purpose of providing substitute data under § 75.37, use a default value of 3.0 percent H₂O as the minimum potential moisture percentage. Alternatively, the minimum potential moisture percentage may be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). If this option is chosen, the minimum potential moisture percentage shall be the lowest quality-assured hourly average H₂O concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.6 Maximum Potential Moisture Percentage

When Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_x emission rate, the owner or operator of a unit that uses a continuous moisture monitoring system shall, for the purpose of providing substitute data under § 75.37, determine the maximum potential moisture percentage. The maximum potential moisture percentage shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The maximum potential moisture percentage shall

be the highest quality-assured hourly average H₂O concentration recorded in the 720 (or more) hours of data used for the determination. Alternatively, a default maximum potential moisture value of 15.0 percent H₂O may be used.

2.2 Design for Quality Control Testing

2.2.1 Pollutant Concentration and CO₂ or O₂ Monitors

- (a) Design and equip each pollutant concentration and CO₂ or O₂ monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).
- (b) Design and equip each pollutant concentration or CO₂ or O₂ monitor to allow daily determinations of calibration error (positive or negative) at the zero- and mid-or high-level concentrations specified in section 5.2 of this appendix.

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

- (a) Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

- (b) Design and equip each differential pressure flow monitor to provide an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).
- (c) Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.
- (d) Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3. Performance Specifications

3.1 Calibration Error

- (a) The calibration error performance specifications in this section apply only to 7-day calibration error tests under sections 6.3.1 and 6.3.2 of this appendix and to the offline calibration demonstration described in section 2.1.1.2 of appendix B to this part. The calibration error limits for daily operation of the continuous monitoring systems required under this part are found in section 2.1.4(a) of appendix B to this part.
- (b) The calibration error of SO₂ and NO_x pollutant concentration monitors shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument, as calculated using Equation A-5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, $|R-A|$ in Equation A-5 of this appendix, is ≤ 5 ppm. The calibration error of CO₂ or O₂ monitors (including O₂ monitors used to measure CO₂ emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by >0.5 percent O₂ or CO₂, as calculated using the term $|R-A|$ in the numerator of Equation A-5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent of the calibration span value of the instrument, as calculated using Equation A-6 of this appendix. For differential pressure-type flow monitors, the calibration error test results are also acceptable if $|R-A|$, the absolute value of the difference between the monitor response and the reference value in Equation A-6, does not exceed 0.01 inches of water.

3.2 Linearity Check

For SO₂ and NO_x pollutant concentration monitors, the error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent (as calculated using equation A-4 of this appendix). Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in equation A-4 of this appendix, is less than or equal to 5 ppm. For CO₂ or O₂ monitors (including O₂ monitors used to measure CO₂ emissions or percent moisture):

- (1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent as calculated using equation A-4 of this appendix; or
- (2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in equation A-4 of this appendix, shall be less than or equal to 0.5 percent CO₂ or O₂, whichever is less restrictive.

3.3 Relative Accuracy

3.3.1 Relative Accuracy for SO₂ Monitors

- (a) The relative accuracy for SO₂ pollutant concentration monitors shall not exceed 10.0 percent except as provided in this section.
- (b) For affected units where the average of the reference method measurements of SO₂ concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the monitor measurements and the reference method mean value shall not exceed ± 15.0 ppm, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_x-Diluent Continuous Emission Monitoring Systems

- (a) The relative accuracy for NO_x-diluent continuous emission monitoring systems shall not exceed 10.0 percent.
- (b) For affected units where the average of the reference method measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ± 0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.3 Relative Accuracy for CO₂ and O₂ Monitors

The relative accuracy for CO₂ and O₂ monitors shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the CO₂ or O₂ monitor measurements and the corresponding reference method measurement mean value, calculated using equation A-7 of this appendix, does not exceed ± 1.0 percent CO₂ or O₂.

3.3.4 Relative Accuracy for Flow Monitors

- (a) The relative accuracy of flow monitors shall not exceed 10.0 percent at any load (or operating) level at which a RATA is performed (i.e., the low, mid, or high level, as defined in section 6.5.2.1 of this appendix).
- (b) For affected units where the average of the flow reference method measurements of gas velocity at a particular load (or operating) level of the relative accuracy test audit is less than or equal to 10.0 fps, the difference between the mean value of the flow monitor velocity measurements and the reference method mean value in fps at that level shall not exceed ± 2.0 fps, wherever the 10.0 percent relative accuracy specification is not achieved.

3.3.5 Combined SO₂/Flow Monitoring System [Reserved]

3.3.6 Relative Accuracy for Moisture Monitoring Systems

The relative accuracy of a moisture monitoring system shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the reference method measurements (in percent H₂O) and the corresponding mean value of the moisture monitoring system measurements (in percent H₂O), calculated using Equation A-7 of this appendix does not exceed ± 1.5 percent H₂O.

3.3.7 Relative Accuracy for NO_x Concentration Monitoring Systems

- (a) The following requirement applies only to NO_x concentration monitoring systems (i.e., NO_x pollutant concentration monitors) that are used to determine NO_x mass emissions, where the owner or operator elects to monitor and report NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system.
- (b) The relative accuracy for NO_x concentration monitoring systems shall not exceed 10.0 percent. Alternatively, for affected units where the average of the reference method measurements of NO_x concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ± 15.0 ppm, wherever the 10.0 percent relative accuracy specification is not achieved.

3.4 Bias

3.4.1 SO₂ Pollutant Concentration Monitors, NO_x Concentration Monitoring Systems and NO_x-Diluent Continuous Emission Monitoring Systems

SO₂ pollutant concentration monitors, NO_x-diluent continuous emission monitoring systems and NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71(a)(2), shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO₂ pollutant concentration monitors and to all NO_x concentration monitoring systems, including those measuring an average SO₂ or NO_x concentration of 250.0 ppm or less, and to all NO_x-diluent continuous emission monitoring systems, including those measuring an average NO_x emission rate of 0.200 lb/mmBtu or less.

3.4.2 Flow Monitors

Flow monitors shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all flow monitors including those measuring an average gas velocity of 10.0 fps or less.

3.5 Cycle Time

The cycle time for pollutant concentration monitors, oxygen monitors used to determine percent moisture, and any other monitoring component of a continuous emission monitoring system that is required to perform a cycle time test shall not exceed 15 minutes.

4. Data Acquisition and Handling Systems

- (a) Automated data acquisition and handling systems shall read and record the entire range of pollutant concentrations and volumetric flow from zero through full-scale and provide a continuous, permanent record of all measurements and required information in an electronic format. These systems also shall have the capability of interpreting and converting the individual output signals from an SO₂ pollutant concentration monitor, a flow monitor, a CO₂ monitor, an O₂ monitor, a NO_x pollutant concentration monitor, a NO_x-diluent CEMS, and a moisture monitoring system to produce a continuous readout of pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (e.g., lb/hr, lb/mmBtu, tons/hr).
- (b) Data acquisition and handling systems shall also compute and record: Monitor calibration error; any bias adjustments to SO₂, NO_x, flow rate, or NO_x emission rate data; and all missing data procedure statistics specified in subpart D of this part.
- (c) For an excepted monitoring system under appendix D or E of this part, data acquisition and handling systems shall:
 - (1) Read and record the full range of fuel flowrate through the upper range value;
 - (2) Calculate and record intermediate values necessary to obtain emissions, such as mass fuel flowrate and heat input rate;
 - (3) Calculate and record emissions in the appropriate units (e.g., lb/hr of SO₂, lb/mmBtu of NO_x);
 - (4) Predict and record NO_x emission rate using the heat input rate and the NO_x/heat input correlation developed under appendix E of this part;
 - (5) Calculate and record all missing data substitution values specified in appendix D or E of this part; and
 - (6) Provide a continuous, permanent record of all measurements and required information in an electronic format.

5. Calibration Gas

5.1 Reference Gases

For the purposes of part 75, calibration gases include the following:

5.1.1 Standard Reference Materials (SRM)

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, MD 20899-0001.

5.1.2 SRM-Equivalent Compressed Gas Primary Reference Material (PRM)

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases.

5.1.3 NIST Traceable Reference Materials

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases that meet the definition for a NIST Traceable Reference Material (NTRM) provided in § 72.2.

5.1.4 EPA Protocol Gases

- (a) An EPA Protocol gas is a calibration gas mixture prepared and analyzed according to Section 2 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, see § 75.6) or such revised procedure as approved by the Administrator.
- (b) EPA Protocol gas concentrations must be certified by an EPA Protocol gas production site to have an analytical uncertainty (95-percent confidence interval) to be not more than plus or minus 2.0 percent (inclusive) of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, see § 75.6).

5.1.5 Research Gas Mixtures

Concentrations of research gas mixtures, as defined in § 72.2 of this chapter, must be certified by the National Institute of Standards and Technology to have an analytical uncertainty (95-percent confidence interval) calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended on August 25, 1999, EPA-600/R-97/121 (incorporated by reference, see § 75.6) to be not more than plus or minus 2.0 percent (inclusive) of the concentration specified on the cylinder label (*i.e.*, the tag value) in order to be used as calibration gas under this part. Inquiries about the RGM program should be directed to: National Institute of Standards and Technology, Analytical Chemistry Division, Chemical Science and Technology Laboratory, B-324 Chemistry, Gaithersburg, MD 20899.

5.1.6 Zero Air Material

Zero air material is defined in § 72.2 of this chapter.

5.1.7 NIST/EPA-Approved Certified Reference Materials

Existing certified reference materials (CRMs) that are still within their certification period may be used as calibration gas.

5.1.8 Gas Manufacturer's Intermediate Standards

Gas manufacturer's intermediate standards is defined in § 72.2 of this chapter.

5.2 Concentrations

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0.0 to 20.0 percent of span, including span for high-scale or both low- and high-scale for SO₂, NO_x, CO₂, and O₂ monitors, as appropriate.

5.2.2 Low-level Concentration

20.0 to 30.0 percent of span, including span for high-scale or both low- and high-scale for SO₂, NO_x, CO₂, and O₂ monitors, as appropriate.

5.2.3 Mid-level Concentration

50.0 to 60.0 percent of span, including span for high-scale or both low- and high-scale for SO₂, NO_x, CO₂, and O₂ monitors, as appropriate.

5.2.4 High-level Concentration

80.0 to 100.0 percent of span, including span for high-scale or both low-and high-scale for SO₂, NO_x, CO₂, and O₂ monitors, as appropriate.

6. Certification Tests and Procedures

6.1 General Requirements

6.1.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO₂ or O₂ monitor, and flow monitor) as specified in sections 1, 2, and 3 of this appendix, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions. Operate the unit(s) during each period when measurements are made. Units may be tested on non-consecutive days. To the extent practicable, test the DAHS software prior to testing the monitoring hardware.

6.1.2 Requirements for Air Emission Testing

- (a) On and after March 27, 2012, all relative accuracy test audits (RATAs) of CEMS under this part, and stack testing under § 75.19 and Appendix E to this part shall be conducted by an Air Emission Testing Body (AETB) which has provided to the owner or operator of a unit subject to this part the documentation required in paragraph (b) of this section, demonstrating its conformance to ASTM D7036-04 (incorporated by reference, see § 75.6).
- (b) The owner or operator shall obtain from the AETB a certification that as of the time of testing the AETB is operating in conformance with ASTM D7036-04 (incorporated by reference, see § 75.6). The AETB's certification may be limited in scope to the tests identified under paragraph (a). The AETB's certification need not extend to other work it may perform. This certification shall be provided in the form of either:
 - (1) A certificate of accreditation or interim accreditation for the relevant test methods issued by a recognized, national accreditation body; or
 - (2) A letter of certification for the relevant test methods signed by a member of the senior management staff of the AETB.
- (c) The owner or operator shall obtain from the AETB the information required under §§ 75.59(a)(15), (b)(6), and (d)(4), as applicable.
- (d) While under no obligation to request the following information from an AETB, to review the information provided by the AETB in response to such a request, or to take any other action related to the response, the owner or operator may find it useful to request that AETBs complying with paragraph (b)(2) of this section provide a copy of the following:
 - (1) The AETB's quality manual. For the purpose of application of 40 CFR part 2, subpart B, AETB's concerned about the potential for public access to confidential business information (CBI) may identify any information subject to such a claim in the copy provided;
 - (2) The results of any internal audits performed by the AETB and any external audits of the AETB during the 12 month period through the previous calendar quarter;
 - (3) Performance data (as defined in ASTM D7036-04 (incorporated by reference, see § 75.6)) collected by the AETB, including corrective actions implemented, during the 12 month period through the previous calendar quarter; and
 - (4) Training records for all on-site technical personnel, including any Qualified Individuals, for the 12 month period through the previous calendar quarter.
- (e) All relative accuracy testing performed pursuant to § 75.74(c)(2)(ii), section 6.5 of appendix A to this part or section 2.3.1 of appendix B to this part, and stack testing under § 75.19 and Appendix E to this part shall be overseen and supervised on site by at least one Qualified Individual, as defined in § 72.2 of this chapter with respect to the methods employed in the test project. If the source owner or operator, or a State, local, or EPA observer, discovers while the test team is still on site, that at least one QI did not oversee and supervise the entire test (as qualified by this paragraph (e)), only those portions of the test that were overseen and supervised by at least one QI as described above may be

used under this part. However, allowance is made for normal activities of a QI who is overseeing and supervising a test, e.g., bathroom breaks, meal breaks, and emergencies that may arise during a test.

- (f) Except as provided in paragraph (e), no RATA performed pursuant to § 75.74(c)(2)(ii), section 6.5 of appendix A to this part or section 2.3.1 of appendix B to this part, and no stack test under § 75.19 or Appendix E to this part (or portion of such a RATA or stack test) conducted by an AETB (as defined in § 72.2) shall be invalidated under this part as a result of the failure of the AETB to conform to ASTM D7036-04 (incorporated by reference, see § 75.6). Validation of such tests is determined based on the other part 75 testing requirements. EPA recommends that proper observation of tests and review of test results continue, regardless of whether an AETB fully conforms to ASTM D7036-04.
- (g) An owner or operator who has requested information from an AETB under paragraph (d) of this part who believes that the information provided by the AETB was either incomplete or inaccurate may request the Administrator's assistance in remedying the alleged deficiencies. Upon such a request, if the Administrator concurs that the information submitted to a source subject to part 75 by an AETB under this section is either incomplete or inaccurate, the Administrator will provide the AETB a description of the deficiencies to be remedied. The Administrator's determination of completeness and accuracy of information will be solely based on the provisions of ASTM D7036-04 (incorporated by reference, see § 75.6) and this part. The Administrator may post the name of the offending AETB on Agency Web sites (including the CAMD Web site <http://www.epa.gov/airmarkets/emissions/aetb.html>) if within 30 days of the Administrator having provided the AETB a description of the deficiencies to be remedied, the AETB does not satisfactorily respond to the source and notify the Administrator of the response by submitting the notification to aetb@epa.gov, unless otherwise provided by the Administrator. The AETB need not submit the information it provides to the owner or operator to the Administrator, unless specifically requested by the Administrator. If after the AETB's name is posted, the Administrator, in consultation with the source, determines that the AETB's response is sufficient, the AETB's name will be removed from the EPA Web sites.

6.2 Linearity Check (General Procedures)

Check the linearity of each SO₂, NO_x, CO₂, and O₂ monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. Notwithstanding these requirements, if the SO₂ or NO_x span value for a particular monitor range is ≤30 ppm, that range is exempted from the linearity check requirements of this part, for initial certification, recertification, and for on-going quality-assurance. For units with two measurement ranges (high and low) for a particular parameter, perform a linearity check on both the low scale (except for SO₂ or NO_x span values ≤30 ppm) and the high scale. Note that for a NO_x-diluent monitoring system with two NO_x measurement ranges, if the low NO_x scale has a span value ≤30 ppm and is exempt from linearity checks, this does not exempt either the diluent monitor or the high NO_x scale (if the span is >30 ppm) from linearity check requirements. For on-going quality assurance of the CEMS, perform linearity checks, using the procedures in this section, on the range(s) and at the frequency specified in section 2.2.1 of appendix B to this part. Challenge each monitor with calibration gas, as defined in

section 5.1 of this appendix, at the low-, mid-, and high-range concentrations specified in section 5.2 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, 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. For in-situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the monitor three times with each reference gas (see example data sheet in Figure 1). Do not use the same gas twice in succession. To the extent practicable, the duration of each linearity test, from the hour of the first injection to the hour of the last injection, shall not exceed 24 unit operating hours. Record the monitor response from the data acquisition and handling system. For each concentration, use the average of the responses to determine the error in linearity using Equation A-4 in this appendix. Linearity checks are acceptable for monitor or monitoring system certification, recertification, or quality assurance if none of the test results exceed the applicable performance specifications in section 3.2 of this appendix. The status of emission data from a CEMS prior to and during a linearity test period shall be determined as follows:

- (a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the linearity test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.
- (b) For the routine quality assurance linearity checks required by section 2.2.1 of appendix B to this part, use the data validation procedures in section 2.2.3 of appendix B to this part.
- (c) When a linearity test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).
- (d) For linearity tests of non-redundant backup monitoring systems, use the data validation procedures in § 75.20(d)(2)(iii).
- (e) For linearity tests performed during a grace period and after the expiration of a grace period, use the data validation procedures in sections 2.2.3 and 2.2.4, respectively, of appendix B to this part.
- (f) For all other linearity checks, use the data validation procedures in section 2.2.3 of appendix B to this part.

6.3 7-Day Calibration Error Test

6.3.1 Gas Monitor 7-Day Calibration Error Test

The following monitors and ranges are exempted from the 7-day calibration error test requirements of this part: the SO₂, NO_x, CO₂ and O₂ monitors installed on peaking units (as defined in § 72.2 of this chapter); and any SO₂ or NO_x measurement range with a span value of 50 ppm or less. In all other cases, measure the calibration error of each SO₂ monitor, each NO_x monitor, and each CO₂ or O₂ monitor while the unit is combusting fuel (but not necessarily

generating electricity) once each day for 7 consecutive operating days according to the following procedures. (In the event that unit outages occur after the commencement of the test, the 7 consecutive unit operating days need not be 7 consecutive calendar days). Units using dual span monitors must perform the calibration error test on both high- and low-scales of the pollutant concentration monitor. The calibration error test procedures in this section and in section 6.3.2 of this appendix shall also be used to perform the daily assessments and additional calibration error tests required under sections 2.1.1 and 2.1.3 of appendix B to this part. Do not make manual or automatic adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day during the 7-day test. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined and recorded. Record and report test results for each day using the unadjusted concentration measured in the calibration error test prior to making any manual or automatic adjustments (*i.e.*, resetting the calibration). The calibration error tests should be approximately 24 hours apart, (unless the 7-day test is performed over nonconsecutive days). Perform calibration error tests at both the zero-level concentration and high-level concentration, as specified in section 5.2 of this appendix. Alternatively, a mid-level concentration gas (50.0 to 60.0 percent of the span value) may be used in lieu of the high-level gas, provided that the mid-level gas is more representative of the actual stack gas concentrations. A calibration gas blend may be used as both a zero-level gas and an upscale (mid- or high-level) gas, where appropriate. In addition, repeat the procedure for SO₂ and NO_x pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only calibration gas, as specified in section 5.1 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, 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. For in-situ type monitors, perform calibration, checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO₂ or O₂ monitors once with each calibration gas. Record the monitor response from the data acquisition and handling system. Using Equation A-5 of this appendix, determine the calibration error at each concentration once each day (at approximately 24-hour intervals) for 7 consecutive days according to the procedures given in this section. The results of a 7-day calibration error test are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix. The status of emission data from a gas monitor prior to and during a 7-day calibration error test period shall be determined as follows:

- (a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.
- (b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.3.2 Flow Monitor 7-day Calibration Error Test

Flow monitors installed on peaking units (as defined in § 72.2 of this chapter) are exempted from the 7-day calibration error test requirements of this part. In all other cases, perform the 7-day calibration error test of a flow monitor, when required for certification, recertification or diagnostic testing, according to the following procedures. Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test while the unit is operating once each unit operating day (as close to 24-hour intervals as practicable). In the event that unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-6 of this appendix. Do not perform any corrective maintenance, repair, or replacement upon the flow monitor during the 7-day test period other than that required in the quality assurance/quality control plan required by appendix B to this part. Do not make adjustments between the zero and high reference level measurements on any day during the 7-day test. If the flow monitor operates within the calibration error performance specification (i.e., less than or equal to 3.0 percent error each day and requiring no corrective maintenance, repair, or replacement during the 7-day test period), the flow monitor passes the calibration error test. Record all maintenance activities and the magnitude of any adjustments. Record output readings from the data acquisition and handling system before and after all adjustments. Record and report all calibration error test results using the unadjusted flow rate measured in the calibration error test prior to resetting the calibration. Record all adjustments made during the 7-day period at the time the adjustment is made, and report them in the certification or recertification application. The status of emissions data from a flow monitor prior to and during a 7-day calibration error test period shall be determined as follows:

- (a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.
- (b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.3.3 For gas or flow monitors installed on peaking units, the exemption from performing the 7-day calibration error test applies as long as the unit continues to meet the definition of a peaking unit in § 72.2 of this chapter. However, if at the end of a particular calendar year or ozone season, it is determined that peaking unit status has been lost, the owner or operator shall perform a diagnostic 7-day calibration error test of each monitor installed on the unit, by no later than December 31 of the following calendar year.

6.4 Cycle Time Test

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures. Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the downscale cycle time, measure the concentration of the flue gas emissions until the response stabilizes. Record the stable emissions value. Inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the time of the zero gas injection, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of the zero gas until the response stabilizes. Record the stable ending calibration gas reading. Determine the downscale cycle time as the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending zero gas reading. Then repeat the procedure, starting with stable stack emissions and injecting the high-level gas, to determine the upscale cycle time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending high-level gas reading. Use the following criteria to assess when a stable reading of stack emissions or calibration gas concentration has been attained. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Alternatively, the reading is considered stable if it changes by no more than 0.5 ppm or 0.2% CO₂ or O₂ (as applicable) for two minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Refer to Figures 6a and 6b in this appendix for example calculations of upscale and downscale cycle times. Report the slower of the two cycle times (upscale or downscale) as the cycle time for the analyzer. Prior to January 1, 2009 for the NO_x-diluent continuous emission monitoring system test, either record and report the longer cycle time of the two component analyzers as the system cycle time or record the cycle time for each component analyzer separately (as applicable). On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, perform the cycle time tests at each probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, at each monitoring location, report the sum of the cycle time observed at that monitoring location plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations of the time-shared systems. For monitors with dual ranges, report the test results for each range separately. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period shall be determined as follows:

- (a) For initial certification, data from the monitor are considered invalid until all certification tests, including the cycle time test, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words "initial certification" apply instead of "recertification," and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.
- (b) When a cycle time test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.5 Relative Accuracy and Bias Tests (General Procedures)

Perform the required relative accuracy test audits (RATAs) as follows for each CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions concentration), each SO₂ pollutant concentration monitor, each NO_x concentration monitoring system used to determine NO_x mass emissions, each flow monitor, each NO_x-diluent CEMS, each O₂ or CO₂ diluent monitor used to calculate heat input, and each moisture monitoring system. For NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71(a)(2), use the same general RATA procedures as for SO₂ pollutant concentration monitors; however, use the reference methods for NO_x concentration specified in section 6.5.10 of this appendix:

- (a) Except as otherwise provided in this paragraph or in § 75.21(a)(5), perform each RATA while the unit (or units, if more than one unit exhausts into the flue) is combusting the fuel that is a normal primary or backup fuel for that unit (for some units, more than one type of fuel may be considered normal, e.g., a unit that combusts gas or oil on a seasonal basis). For units that co-fire fuels as the predominant mode of operation, perform the RATAs while co-firing. For Hg monitoring systems, perform the RATAs while the unit is combusting coal. When relative accuracy test audits are performed on CEMS installed on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.
- (b) Perform each RATA at the load (or operating) level(s) specified in section 6.5.1 or 6.5.2 of this appendix or in section 2.3.1.3 of appendix B to this part, as applicable.
- (c) For monitoring systems with dual ranges, perform the relative accuracy test on the range normally used for measuring emissions. For units with add-on SO₂ or NO_x controls that operate continuously rather than seasonally, or for units that need a dual range to record high concentration "spikes" during startup conditions, the low range is considered normal. However, for some dual span units (e.g., for units that use fuel switching or for which the emission controls are operated seasonally), provided that both monitor ranges are connected to a common probe and sample interface, either of the two measurement ranges may be considered normal; in such cases, perform the RATA on the range that is in use at the time of the scheduled test. If the low and high measurement ranges are connected to separate sample probes and interfaces, RATA testing on both ranges is required.
- (d) Record monitor or monitoring system output from the data acquisition and handling system.
- (e) Complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter). For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit (or stack) operating hours; however, if this is not possible, up to 720 consecutive unit (or stack) operating hours may be taken to complete a multiple-load flow RATA.
- (f) The status of emission data from the CEMS prior to and during the RATA test period shall be determined as follows:
 - (1) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the RATA, have been successfully completed, unless the conditional data validation procedures in § 75.20(b)(3) are used. When the

procedures in § 75.20(b)(3) are followed, the words “initial certification” apply instead of “recertification,” and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

- (2) For the routine quality assurance RATAs required by section 2.3.1 of appendix B to this part, use the data validation procedures in section 2.3.2 of appendix B to this part.
 - (3) For recertification RATAs, use the data validation procedures in § 75.20(b)(3).
 - (4) For quality assurance RATAs of non-redundant backup monitoring systems, use the data validation procedures in §§ 75.20(d)(2)(v) and (vi).
 - (5) For RATAs performed during and after the expiration of a grace period, use the data validation procedures in sections 2.3.2 and 2.3.3, respectively, of appendix B to this part.
 - (6) For all other RATAs, use the data validation procedures in section 2.3.2 of appendix B to this part.
- (g) For each SO₂ or CO₂ emissions concentration monitor, each flow monitor, each CO₂ or O₂ diluent monitor used to determine heat input, each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), each moisture monitoring system, and each NO_x-diluent CEMS, calculate the relative accuracy, in accordance with section 7.3 or 7.4 of this appendix, as applicable. In addition (except for CO₂, O₂, or moisture monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

6.5.1 Gas Monitoring System RATAs (Special Considerations)

- (a) Perform the required relative accuracy test audits for each SO₂ or CO₂ emissions concentration monitor, each CO₂ or O₂ diluent monitor used to determine heat input, each NO_x-diluent CEMS, and each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), at the normal load level or normal operating level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels or operating levels have been designated as normal, the RATAs may be done at either load (or operating) level.
- (b) For the initial certification of a gas monitoring system and for recertifications in which, in addition to a RATA, one or more other tests are required (*i.e.*, a linearity test, cycle time test, or 7-day calibration error test), EPA recommends that the RATA not be commenced until the other required tests of the CEMS have been passed.

6.5.2 Flow Monitor RATAs (Special Considerations)

- (a) Except as otherwise provided in paragraph (b) or (e) of this section, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels or operating levels within the range of operation, as defined in section 6.5.2.1 of this appendix. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load or operating level combinations for the units exhausting to the common stack. Select

the three exhaust gas velocities such that the audit points at adjacent load or operating levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production or in ft/sec, as applicable), are separated by no less than 25.0 percent of the range of operation, as defined in section 6.5.2.1 of this appendix.

- (b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audits for initial certification and recertification shall be single-load tests, performed at the normal load, as defined in section 6.5.2.1(d) of this appendix.
- (c) Flow monitor recertification RATAs shall be done at three load level(s) (or three operating levels), unless otherwise specified in paragraph (b) or (e) of this section or unless otherwise specified or approved by the Administrator.
- (d) The semiannual and annual quality assurance flow monitor RATAs required under appendix B to this part shall be done at the load level(s) (or operating levels) specified in section 2.3.1.3 of appendix B to this part.
- (e) For flow monitors installed on units that do not produce electrical or thermal output, the flow RATAs for initial certification or recertification may be done at fewer than three operating levels, if:
 - (1) The owner or operator provides a technical justification in the hardcopy portion of the monitoring plan for the unit required under § 75.53(e)(2), demonstrating that the unit operates at only one level or two levels during normal operation (excluding unit startup and shutdown). Appropriate documentation and data must be provided to support the claim of single-level or two-level operation; and
 - (2) The justification provided in paragraph (e)(1) of this section is deemed to be acceptable by the permitting authority.

6.5.2.1 Range of Operation and Normal Load (or Operating) Level(s)

- (a) The owner or operator shall determine the upper and lower boundaries of the “range of operation” as follows for each unit (or combination of units, for common stack configurations):
 - (1) For affected units that produce electrical output (in megawatts) or thermal output (in klb/hr of steam production or mmBtu/hr), the lower boundary of the range of operation of a unit shall be the minimum safe, stable loads for any of the units discharging through the stack. Alternatively, for a group of frequently-operated units that serve a common stack, the sum of the minimum safe, stable loads for the individual units may be used as the lower boundary of the range of operation. The upper boundary of the range of operation of a unit shall be the maximum sustainable load. The “maximum sustainable load” is the higher of either: the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings; or the highest sustainable load, based on at least four quarters of representative historical operating data. For common stacks, the maximum sustainable load is the sum of all of the maximum sustainable loads of the individual units discharging through the stack, unless this load is unattainable in practice, in which case use the highest sustainable combined load for the units that discharge through the stack. Based on at least four quarters of representative historical operating data. The load values for the unit(s) shall be expressed either in units of megawatts or thousands of lb/hr of steam load or mmBtu/hr of thermal output; or

- (2) For affected units that do not produce electrical or thermal output, the lower boundary of the range of operation shall be the minimum expected flue gas velocity (in ft/sec) during normal, stable operation of the unit. The upper boundary of the range of operation shall be the maximum potential flue gas velocity (in ft/sec) as defined in section 2.1.4.1 of this appendix. The minimum expected and maximum potential velocities may be derived from the results of reference method testing or by using Equation A-3a or A-3b (as applicable) in section 2.1.4.1 of this appendix. If Equation A-3a or A-3b is used to determine the minimum expected velocity, replace the word "maximum" with the word "minimum" in the definitions of "MPV," " H_f ," " $\% O_{2d}$," and " $\% H_2O$," and replace the word "minimum" with the word "maximum" in the definition of " CO_{2d} ." Alternatively, 0.0 ft/sec may be used as the lower boundary of the range of operation.
- (b) The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: the "low" operating level shall be the first 30.0 percent of the range of operation; the "mid" operating level shall be the middle portion (>30.0 percent, but ≤ 60.0 percent) of the range of operation; and the "high" operating level shall be the upper end (>60.0 percent) of the range of operation. For example, if the upper and lower boundaries of the range of operation are 100 and 1100 megawatts, respectively, then the low, mid, and high operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700 to 1100 megawatts, respectively.
- (c) Units that do not produce electrical or thermal output are exempted from the requirements of this paragraph, (c). The owner or operator shall identify, for each affected unit or common stack (except for peaking units and units using the low mass emissions (LME) excepted methodology under § 75.19), the "normal" load level or levels (low, mid or high), based on the operating history of the unit(s). To identify the normal load level(s), the owner or operator shall, at a minimum, determine the relative number of operating hours at each of the three load levels, low, mid and high over the past four representative operating quarters. The owner or operator shall determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used during that time period. A summary of the data used for this determination and the calculated results shall be kept on-site in a format suitable for inspection. For new units or newly-affected units, the data analysis in this paragraph may be based on fewer than four quarters of data if fewer than four representative quarters of historical load data are available. Or, if no historical load data are available, the owner or operator may designate the normal load based on the expected or projected manner of operating the unit. However, in either case, once four quarters of representative data become available, the historical load analysis shall be repeated.
- (d) Determination of normal load (or operating level)
 - (1) Based on the analysis of the historical load data described in paragraph (c) of this section, the owner or operator shall, for units that produce electrical or thermal output, designate the most frequently used load level as the normal load level for the unit (or combination of units, for common stacks). The owner or operator may also designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units and LME units, normal load designations are unnecessary; the entire operating load range shall be considered normal. If the manner of operation of the unit changes significantly, such that the designated normal load(s) or the two most frequently used load levels change, the owner or operator shall repeat the historical load analysis and shall redesignate the normal load(s) and the two most frequently used load levels, as appropriate. A minimum of two representative quarters of historical load data are required

to document that a change in the manner of unit operation has occurred. Update the electronic monitoring plan whenever the normal load level(s) and the two most frequently-used load levels are redesignated.

- (2) For units that do not produce electrical or thermal output, the normal operating level(s) shall be determined using sound engineering judgment, based on knowledge of the unit and operating experience with the industrial process.
- (e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as applicable), in the electronic monitoring plan required under § 75.53. Except for peaking units and LME units, the owner or operator shall indicate, in the electronic monitoring plan, the load level (or levels) designated as normal under this section and shall also indicate the two most frequently used load levels.

6.5.2.2 Multi-Load (or Multi-Level) Flow RATA Results

For each multi-load (or multi-level) flow RATA, calculate the flow monitor relative accuracy at each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA must be repeated at that load (or operating) level. However, the entire 2-level (or 3-level) relative accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients or K-factor(s) are changed, in which case a 3-level RATA is required (or, a 2-level RATA, for units demonstrated to operate at only two levels, under section 6.5.2(e) of this appendix).

6.5.3 [Reserved]

6.5.4 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy and bias in accordance with the procedures and equations specified in section 7 of this appendix.

6.5.5 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Performance Specification 2 in appendix B of part 60 of this chapter for SO₂ and NO_x continuous emission monitoring systems, Performance Specification 3 in appendix B of part 60 of this chapter for CO₂ or O₂ monitors, or method 1 (or 1A) in appendix A of part 60 of this chapter for volumetric flow, except as otherwise indicated in this section or as approved by the Administrator.

6.5.6 Reference Method Traverse Point Selection

Select traverse points that ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section. To achieve this, the reference method traverse points shall meet the requirements of section 8.1.3 of Performance Specification 2 ("PS No. 2") in

appendix B to part 60 of this chapter (for SO₂, NO_x, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O₂ and CO₂ monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs), Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to part 60 of this chapter. The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs:

- (a) For moisture determinations where the moisture data are used only to determine stack gas molecular weight, a single reference method point, located at least 1.0 meter from the stack wall, may be used. For moisture monitoring system RATAs and for gas monitor RATAs in which moisture data are used to correct pollutant or diluent concentrations from a dry basis to a wet basis (or vice-versa), single-point moisture sampling may only be used if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed prior to the RATA for at least one pollutant or diluent gas, and if the test is passed according to the acceptance criteria in section 6.5.6.3(b) of this appendix.
- (b) For gas monitoring system RATAs, the owner or operator may use any of the following options:
 - (1) At any location (including locations where stratification is expected), use a minimum of six traverse points along a diameter, in the direction of any expected stratification. The points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.
 - (2) At locations where section 8.1.3 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.2, and 2.0 meters from the stack wall), the owner or operator may use an alternative 3-point measurement line, locating the three points at 4.4, 14.6, and 29.6 percent of the way across the stack, in accordance with Method 1 in appendix A to part 60 of this chapter.
 - (3) At locations where stratification is likely to occur (e.g., following a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 8.1.3 of PS No. 2 (or the alternative line described in paragraph (b)(2) of this section) may be used in lieu of the prescribed "long" measurement line in section 8.1.3 of PS No. 2, provided that the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix).
 - (4) A single reference method measurement point, located no less than 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used at any sampling location if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed prior to each RATA at the location (according to the acceptance criteria of section 6.5.6.3(b) of this appendix).
 - (5) If Method 7E is used as the reference method for the RATA of a NO_x CEMS installed on a combustion turbine, the reference method measurements may be made at the sampling points specified in section 6.1.2 of Method 20 in appendix A to part 60 of this chapter.

6.5.6.1 Stratification Test

- (a) With the unit(s) operating under steady-state conditions at the normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO₂ or NO_x) and diluent (CO₂ or O₂) concentrations at a minimum of twelve (12) points, located according to Method 1 in appendix A to part 60 of this chapter.
- (b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality-assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.
- (c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 2-hour period.
- (d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.
- (e) Calculate the average NO_x, SO₂, and CO₂ (or O₂) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_x, SO₂, and CO₂ (or O₂) concentrations for all traverse points.

6.5.6.2 Alternative (Abbreviated) Stratification Test

- (a) With the unit(s) operating under steady-state conditions at normal load level (or normal operating level), as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO₂ or NO_x) and diluent (CO₂ or O₂) concentrations at three points. The points shall be located according to the specifications for the long measurement line in section 8.1.3 of PS No. 2 (i.e., locate the points 16.7 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively, the concentration measurements may be made at six traverse points along a diameter. The six points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.
- (b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality-assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.
- (c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 1-hour period.
- (d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.
- (e) Calculate the average NO_x, SO₂, and CO₂ (or O₂) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_x, SO₂, and CO₂ (or O₂) concentrations for all traverse points.

6.5.6.3 Stratification Test Results and Acceptance Criteria

- (a) For each pollutant or diluent gas, the short reference method measurement line described in section 8.1.3 of PS No. 2 may be used in lieu of the long measurement line prescribed in section 8.1.3 of PS No. 2 if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(3) of this appendix), show that the concentration at each individual traverse point differs by no more than ± 10.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ± 5 ppm or ± 0.5 percent CO₂ (or O₂) from the arithmetic average concentration for all traverse points.
- (b) For each pollutant or diluent gas, a single reference method measurement point, located at least 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used for that pollutant or diluent gas if the results of a stratification test, conducted in accordance with section 6.5.6.1 of this appendix, show that the concentration at each individual traverse point differs by no more than ± 5.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ± 3 ppm or ± 0.3 percent CO₂ (or O₂) from the arithmetic average concentration for all traverse points.
- (c) The owner or operator shall keep the results of all stratification tests on-site, in a format suitable for inspection, as part of the supplementary RATA records required under § 75.59(a)(7).

6.5.7 Sampling Strategy

- (a) Conduct the reference method tests allowed in section 6.5.10 of this appendix so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO₂ or O₂ monitor, flow monitor, and SO₂ or NO_x CEMS measurements. The minimum acceptable time for a gas monitoring system RATA run or for a moisture monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant concentration measurements, diluent concentration measurements, and moisture measurements (if applicable) must, to the extent practicable, be made within a 60-minute period. For NO_x-diluent monitoring system RATAs, the pollutant and diluent concentration measurements must be made simultaneously. For flow monitor RATAs, the minimum time per run shall be 5 minutes. Flow rate reference method measurements allowed in section 6.5.10 of this appendix may be made either sequentially from port-to-port or simultaneously at two or more sample ports. The velocity measurement probe may be moved from traverse point to traverse point either manually or automatically. If, during a flow RATA, significant pulsations in the reference method readings are observed, be sure to allow enough measurement time at each traverse point to obtain an accurate average reading when a manual readout method is used (e.g., a "sight-weighted" average from a manometer). Also, allow sufficient measurement time to ensure that stable temperature readings are obtained at each traverse point, particularly at the first measurement point at each sample port, when a probe is moved sequentially from port-to-port. A minimum of one set of auxiliary measurements for stack gas molecular weight determination (i.e., diluent gas data and moisture data) is required for every clock hour of a flow RATA or for every three test runs (whichever is less restrictive). Alternatively, moisture

measurements for molecular weight determination may be performed before and after a series of flow RATA runs at a particular load level (low, mid, or high), provided that the time interval between the two moisture measurements does not exceed three hours. If this option is selected, the results of the two moisture determinations shall be averaged arithmetically and applied to all RATA runs in the series. Successive flow RATA runs may be performed without waiting in between runs. If an O₂ diluent monitor is used as a CO₂ continuous emission monitoring system, perform a CO₂ system RATA (i.e., measure CO₂, rather than O₂, with the applicable reference method allowed in section 6.5.10 of this appendix). For moisture monitoring systems, an appropriate coefficient, "K" factor or other suitable mathematical algorithm may be developed prior to the RATA, to adjust the monitoring system readings with respect to the applicable reference method allowed in section 6.5.10 of this appendix. If such a coefficient, K-factor or algorithm is developed, it shall be applied to the CEMS readings during the RATA and (if the RATA is passed), to the subsequent CEMS data, by means of the automated data acquisition and handling system. The owner or operator shall keep records of the current coefficient, K factor or algorithm, as specified in § 75.59(a)(5)(vii). Whenever the coefficient, K factor or algorithm is changed, a RATA of the moisture monitoring system is required.

- (b) To properly correlate individual SO₂ or NO_x CEMS data (in lb/mmBtu) and volumetric flow rate data with the applicable reference method data, annotate the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

6.5.8 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow monitor measures flow rate on a wet basis, method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO₂, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, recertification, diagnostic, semiannual, or annual) relative accuracy test audit. For 2-level and 3-level relative accuracy test audits of flow monitors, perform a minimum of nine sets at each of the operating levels.

Note: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results, as long as the

total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected CEMS data and corresponding reference method test results.

6.5.10 Reference Methods

The following methods are from appendix A to part 60 of this chapter, and are the reference methods for performing relative accuracy test audits under this part: Method 1 or 1A in appendix A-1 to part 60 of this chapter for siting; Method 2 in appendix A-1 to part 60 of this chapter or its allowable alternatives in appendices A-1 and A-2 to part 60 of this chapter (except for Methods 2B and 2E in appendix A-1 to part 60 of this chapter) for stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B in appendix A-2 to part 60 of this chapter for O₂ and CO₂; Method 4 in appendix A-3 to part 60 of this chapter for moisture; Methods 6, 6A or 6C in appendix A-4 to part 60 of this chapter for SO₂; and Methods 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60 of this chapter for NO_x, excluding the exceptions to Method 7E identified in § 75.22(a)(5). When using Method 7E for measuring NO_x concentration, total NO_x, including both NO and NO₂, must be measured. When using EPA Protocol gas with Methods 3A, 6C, and 7E, the gas must be from an EPA Protocol gas production site that is participating in the EPA Protocol Gas Verification Program, pursuant to § 75.21(g)(6). An EPA Protocol gas cylinder certified by or ordered from a non-participating production site no later than May 27, 2011 may be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig; however, in no case shall the cylinder be recertified by a non-participating EPA Protocol gas production site to extend its useful life and be used by a source subject to this part. In the event that an EPA Protocol gas production site is removed from the list of PGVP participants on the same date as or after the date on which a particular cylinder is certified or ordered, that gas cylinder may continue to be used for the purposes of this part until the earlier of the cylinder's expiration date or the date on which the cylinder gas pressure reaches 150 psig; however, in no case shall the cylinder be recertified by a non-participating EPA Protocol gas production site to extend its useful life and be used by a source subject to this part.

7. Calculations

7.1 Linearity Check

Analyze the linearity data for pollutant concentration and CO₂ or O₂ monitors as follows. Calculate the percentage error in linearity based upon the reference value at the low-level, mid-level, and high-level concentrations specified in section 6.2 of this appendix. Perform this calculation once during the certification test. Use the following equation to calculate the error in linearity for each reference value.

$$LE = \frac{|R-A|}{R} \times 100$$

(Eq. A-4)

where,

LE = Percentage Linearity error, based upon the reference value.

R = Reference value of Low-, mid-, or high-level calibration gas introduced into the monitoring system.

A = Average of the monitoring system responses.

7.2 Calibration Error

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A-5)

where,

CE = Calibration error as a percentage of the span of the instrument.

R = Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span of the instrument, as specified in section 2 of this appendix.

7.2.2 Flow Monitor Calibration Error

For each reference value, calculate the percentage calibration error based upon span using the following equation:

$$CE = \frac{|R-A|}{S} \times 100 \quad (\text{Eq. A-6})$$

where:

CE = Calibration error as a percentage of span.

R = Low or high level reference value specified in section 2.2.2.1 of this appendix.

A = Actual flow monitor response to the reference value.

S = Flow monitor calibration span value as determined under section 2.1.4.2 of this appendix.

7.3 Relative Accuracy for SO₂ and CO₂ Emissions Concentration Monitors, O₂ Monitors, NO_x Concentration Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO₂ and CO₂ emissions concentration monitors, CO₂ or O₂ monitors used for heat input rate determination, NO_x concentration monitoring systems used to determine NO_x mass emissions under subpart H of this part, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

7.3.1 Arithmetic Mean

Calculate the arithmetic mean of the differences of a data set as follows:

$$\bar{d} = \frac{1}{n} \sum_{i=1}^n d_i \quad (\text{Eq. A-7})$$

Where:

$\bar{d}$ = Arithmetic mean of the differences

n = Number of data points (test runs)

$\sum_{i=1}^n d_i$ = Algebraic sum of the individual differences d_i

d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value ($RM_i - CEM_i$), for a given data point

7.3.2 Standard Deviation

Calculate the standard deviation, S_d , of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^n d_i^2 - \frac{\left(\sum_{i=1}^n d_i\right)^2}{n}}{n-1}}$$

(Eq. A-8)

7.3.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025} \frac{S_d}{\sqrt{n}}$$

(eq. A-9)

where,

$t_{0.025}$ = t value (see table 7-1).

TABLE 7-1—T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|d| + |cc|}{\overline{RM}} \times 100$$

(Eq. A-10)

where,

RM = Arithmetic mean of the reference method values.

|d| = The absolute value of the mean difference between the reference method values and the corresponding continuous emission monitoring system values.

|cc| = The absolute value of the confidence coefficient.

7.4 Relative Accuracy for NO_x-diluent Continuous Emission Monitoring Systems

Analyze the relative accuracy test audit data from the reference method tests for NO_x-diluent continuous emissions monitoring system as follows.

7.4.1 Data Preparation

If C_{NO_x}, the NO_x concentration, is in ppm, multiply it by 1.194 × 10⁻⁷ (lb/dscf)/ppm to convert it to units of lb/dscf. If C_{NO_x} is in mg/dscm, multiply it by 6.24 × 10⁻⁸ (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O₂ or CO₂) reference method results for the run and the appropriate F or F_c factor from table 1 in appendix F of this part to convert C_{NO_x} from lb/dscf to lb/mmBtu units. Use the equations and procedure in section 3 of appendix F to this part, as appropriate.

7.4.2 NO_x Emission Rate

For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 4.

7.4.3 Relative Accuracy

Use the equations and procedures in section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using equation A-7, "d" is, for each run, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

7.5 Relative Accuracy for Combined SO₂/Flow [Reserved]

7.6 Bias Test and Adjustment Factor

Test the following relative accuracy test audit data sets for bias: SO₂ pollutant concentration monitors; flow monitors; NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in 75.71(a)(2); and NO_x-diluent CEMS using the procedures outlined in sections 7.6.1 through 7.6.5 of this appendix. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under section 6.5.2.1 of this appendix.

7.6.1 Arithmetic Mean

Calculate the arithmetic mean of the differences of the data set using Equation A-7 of this appendix. To calculate bias for an SO₂ or NO_x pollutant concentration monitor, "d_i" is, for each paired data point, the difference between the SO₂ or NO_x concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d_i" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x-diluent continuous emission monitoring system, "d_i" is, for each paired data point, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system.

7.6.2 Standard Deviation

Calculate the standard deviation, S_d, of the data set using equation A-8.

7.6.3 Confidence Coefficient

Calculate the confidence coefficient, cc, of the data set using equation A-9.

7.6.4 Bias Test

If, for the relative accuracy test audit data set being tested, the mean difference, $\bar{d}$, is less than or equal to the absolute value of the confidence coefficient, |cc|, the monitor or monitoring system has passed the bias test. If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, $\sqrt{cc}$, the monitor or monitoring system has failed to meet the bias test requirement.

7.6.5 Bias Adjustment

- (a) If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$$CEM_i^{Adjusted} = CEM_i^{Monitor} \times BAF \quad (Eq. A-11)$$

Where:

$CEM_i^{Monitor}$ = Data (measurement) provided by the monitor at time i.

$CEM_i^{Adjusted}$ = Data value, adjusted for bias, at time i.

BAF = Bias adjustment factor, defined by:

$$\text{BAF} = 1 + \frac{|\bar{d}|}{\text{CEM}_{\text{avg}}} \quad (\text{Eq. A-12})$$

Where:

BAF = Bias adjustment factor, calculated to the nearest thousandth.

$\bar{d}$ = Arithmetic mean of the difference obtained during the failed bias test using Equation A-7.

CEM_{avg} = Mean of the data values provided by the monitor during the failed bias test.

- (b) For single-load RATAs of SO₂ pollutant concentration monitors, NO_x concentration monitoring systems, and NO_x-diluent monitoring systems, and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A-12. Notwithstanding, when a NO_x concentration CEMS or an SO₂ CEMS or a NO_x-diluent CEMS installed on a low-emitting affected unit (*i.e.*, average SO₂ or NO_x concentration during the RATA ≤250 ppm or average NO_x emission rate ≤0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A-10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may either be determined using Equation A-12, or a default BAF of 1.111 may be used.
- (c) For 2-load or 3-load flow RATAs, when only one load level (low, mid or high) has been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at the normal load level, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at the normal load level, use Equation A-12 to calculate the normal load BAF and then perform an additional bias test at the second most frequently-used load level, as determined under section 6.5.2.1 of this appendix. If the bias test is passed at this second load level, apply the normal load BAF to the subsequent flow rate data. If the bias test is failed at this second load level, use Equation A-12 to calculate the BAF at the second load level and apply the higher of the two BAFs (either from the normal load level or from the second load level) to the subsequent flow rate data.
- (d) For 2-load or 3-load flow RATAs, when two load levels have been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at both normal load levels, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at one of the normal load levels but not at the other, use Equation A-12 to calculate the BAF for the normal load level at which the bias test was failed and apply that BAF to the subsequent flow rate data. If the bias test is failed at both designated normal load levels, use Equation A-12 to calculate the BAF at each normal load level and apply the higher of the two BAFs to the subsequent flow rate data.

- (e) Each time a RATA is passed and the appropriate bias adjustment factor has been determined, apply the BAF prospectively to all monitoring system data, beginning with the first clock hour following the hour in which the RATA was completed. For a 2-load flow RATA, the "hour in which the RATA was completed" refers to the hour in which the testing at both loads was completed; for a 3-load RATA, it refers to the hour in which the testing at all three loads was completed.
- (f) Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO₂, the flow rate, the average NO_x emission rate, the unit heat input, and the calculated mass emissions of SO₂ and CO₂ during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a NO_x concentration monitoring system and a flow monitor to calculate NO_x mass emissions under subpart H of this part, use bias-adjusted values for NO_x concentration and flow rate in the mass emission calculations and use bias-adjusted NO_x concentrations to compute the appropriate substitution values for NO_x concentration in the missing data routines under subpart D of this part.
- (g) For units that do not produce electrical or thermal output, the provisions of paragraphs (a) through (f) of this section apply, except that the terms, "single-load", "2-load", "3-load", and "load level" shall be replaced, respectively, with the terms, "single-level", "2-level", "3-level", and "operating level".

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

- (a) Except as provided in section 7.8 of this appendix, the owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a passing flow RATA is performed at a load level designated as normal in section 6.5.2.1 of this appendix. The owner or operator shall report the current value of R_{ref} in the electronic quarterly report required under § 75.64 and shall also report the completion date of the associated RATA. If two load levels have been designated as normal under section 6.5.2.1 of this appendix, the owner or operator shall determine a separate R_{ref} value for each of the normal load levels. The reference flow-to-load ratio shall be calculated as follows:

$$R_{\text{ref}} = \frac{Q_{\text{ref}}}{L_{\text{avg}}} \times 10^{-5} \quad (\text{Eq. A-13})$$

Where:

R_{ref} = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr of steam output).

Q_{ref} = Average stack gas volumetric flow rate measured by the reference method during the normal-load RATA, scfh.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr of thermal output.

- (b) In Equation A-13, for a common stack, determine L_{avg} by summing, for each RATA run, the operating loads of all units discharging through the common stack, and then taking the arithmetic average of the summed loads. For a unit that discharges its emissions through

multiple stacks, either determine a single value of Q_{ref} for the unit or a separate value of Q_{ref} for each stack. In the former case, calculate Q_{ref} by summing, for each RATA run, the volumetric flow rates through the individual stacks and then taking the arithmetic average of the summed RATA run flow rates. In the latter case, calculate the value of Q_{ref} for each stack by taking the arithmetic average, for all RATA runs, of the flow rates through the stack. For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack (e.g., a unit with a wet SO₂ scrubber), determine Q_{ref} separately for each stack at the time of the normal load flow RATA. Round off the value of R_{ref} to two decimal places.

- (c) In addition to determining R_{ref} or as an alternative to determining R_{ref} , a reference value of the gross heat rate (GHR) may be determined. In order to use this option, quality-assured diluent gas (CO₂ or O₂) must be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR shall be determined as follows:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000 \quad (\text{Eq. A-13a})$$

Where:

$(GHR)_{ref}$ = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh, Btu/lb steam load, or Btu heat input/mmBtu steam output.

$(\text{Heat Input})_{avg}$ = Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr. For multiple stack configurations, if the reference GHR value is determined separately for each stack, use the hourly heat input measured at each stack. If the reference GHR is determined at the unit level, sum the hourly heat inputs measured at the individual stacks.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

- (d) In the calculation of $(\text{Heat Input})_{avg}$, use Q_{ref} , the average volumetric flow rate measured by the reference method during the RATA, and use the average diluent gas concentration measured during the flow RATA (i.e., the arithmetic average of the diluent gas concentrations for all clock hours in which a RATA run was performed).

7.8 Flow-to-Load Test Exemptions

- (a) For complex stack configurations (e.g., when the effluent from a unit is divided and discharges through multiple stacks in such a manner that the flow rate in the individual stacks cannot be correlated with unit load), the owner or operator may petition the Administrator under § 75.66 for an exemption from the requirements of section 7.7 of this appendix and section 2.2.5 of appendix B to this part. The petition must include sufficient information and data to demonstrate that a flow-to-load or gross heat rate evaluation is infeasible for the complex stack configuration.

- (b)
- Units that do not produce electrical output (in megawatts) or thermal output (in klb of steam per hour) are exempted from the flow-to-load ratio test requirements of section 7.7 of this appendix and section 2.2.5 of appendix B to this part.

FIGURE 1 TO APPENDIX A—LINEARITY ERROR DETERMINATION

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level:					
Mid-level:					
High-level:					

FIGURE 2 TO APPENDIX A—RELATIVE ACCURACY DETERMINATION (POLLUTANT CONCENTRATION MONITORS)

Run No.	Date and time	SO ₂ (ppm ^c)			Date and time	CO ₂ (Pollutant) (ppm ^c)		
		RM ^a	M ^b	Diff		RM ^a	M ^b	Diff
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).								

^a RM means "reference method data."

^b M means "monitor data."

^c Make sure the RM and M data are on a consistent basis, either wet or dry.

FIGURE 3 TO APPENDIX A—RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date and time	Flow rate (Low) (scf/hr)*			Date and time	Flow rate (Normal) (scf/hr)*			Date and time	Flow rate (High) (scf/hr)*		
		RM	M	Diff		RM	M	Diff		RM	M	Diff
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).												

* Make sure the RM and M data are on a consistent basis, either wet or dry.

FIGURE 4 TO APPENDIX A—RELATIVE ACCURACY DETERMINATION (NO_x/DILUENT COMBINED SYSTEM)

Run No.	Date and time	Reference method data		NO _x system (lb/mmBtu)		
		NO _x () ^a	O ₂ /CO ₂ %	RM	M	Difference
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Arithmetic Mean Difference (Eq. A-7). Confidence Coefficient (Eq. A-9). Relative Accuracy (Eq. A-10).						

^a Specify units: ppm, lb/dscf, mg/dscm.

Figure 5—Cycle Time

Date of test _____

Component/system ID#: _____

Analyzer type _____

Serial Number _____

High level gas concentration: _____ ppm/% (circle one)

Zero level gas concentration: _____ ppm/% (circle one)

Analyzer span setting: _____ ppm/% (circle one)

Upscale:

Stable starting monitor value: _____ ppm/% (circle one)

Stable ending monitor reading: _____ ppm/% (circle one)

Elapsed time: _____ seconds

Downscale:

Stable starting monitor value: _____ ppm/% (circle one)

Stable ending monitor value: _____ ppm/% (circle one)

Elapsed time: _____ seconds

Component cycle time= _____ seconds

System cycle time= _____ seconds

Figure 6a. Upscale Cycle Time Test

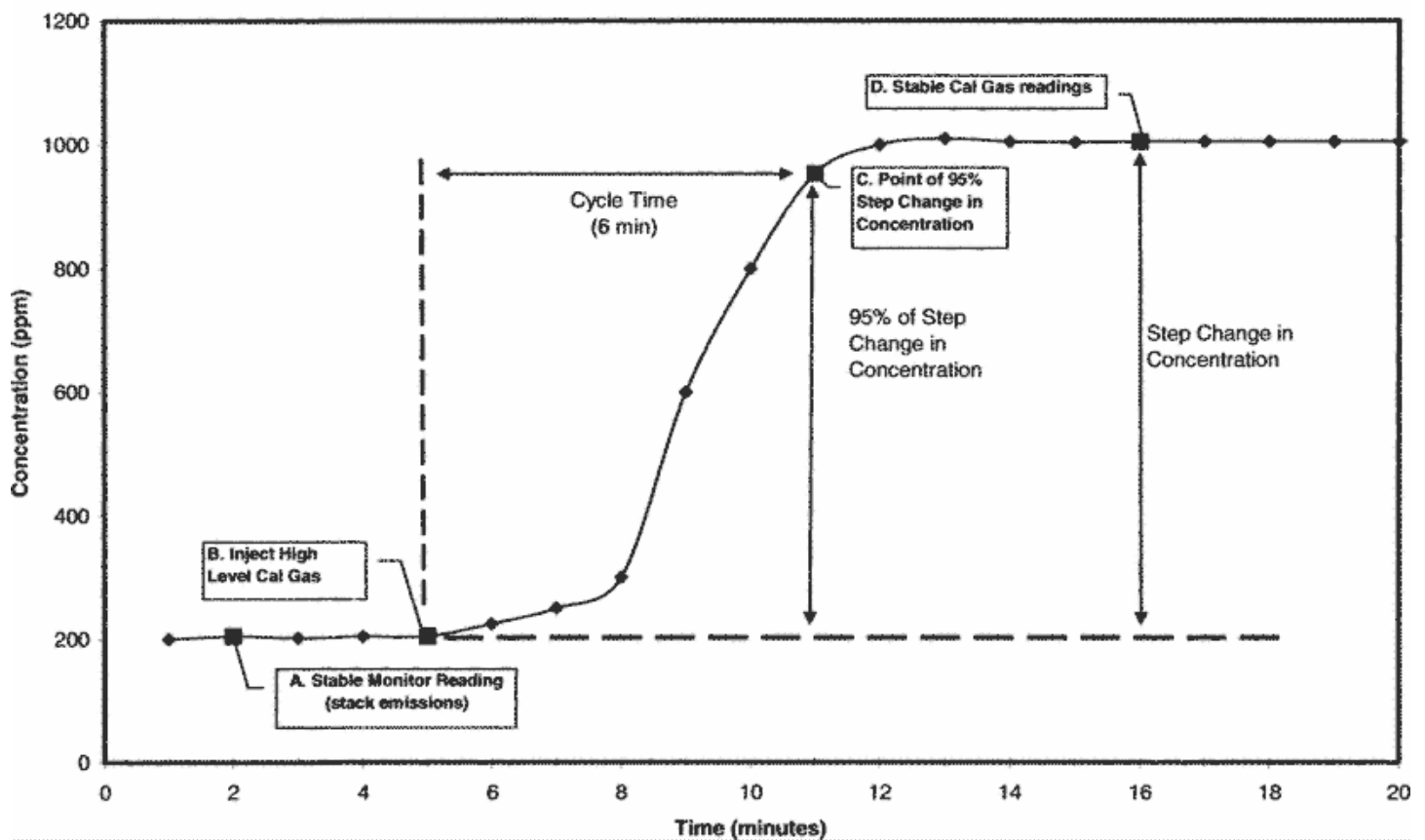
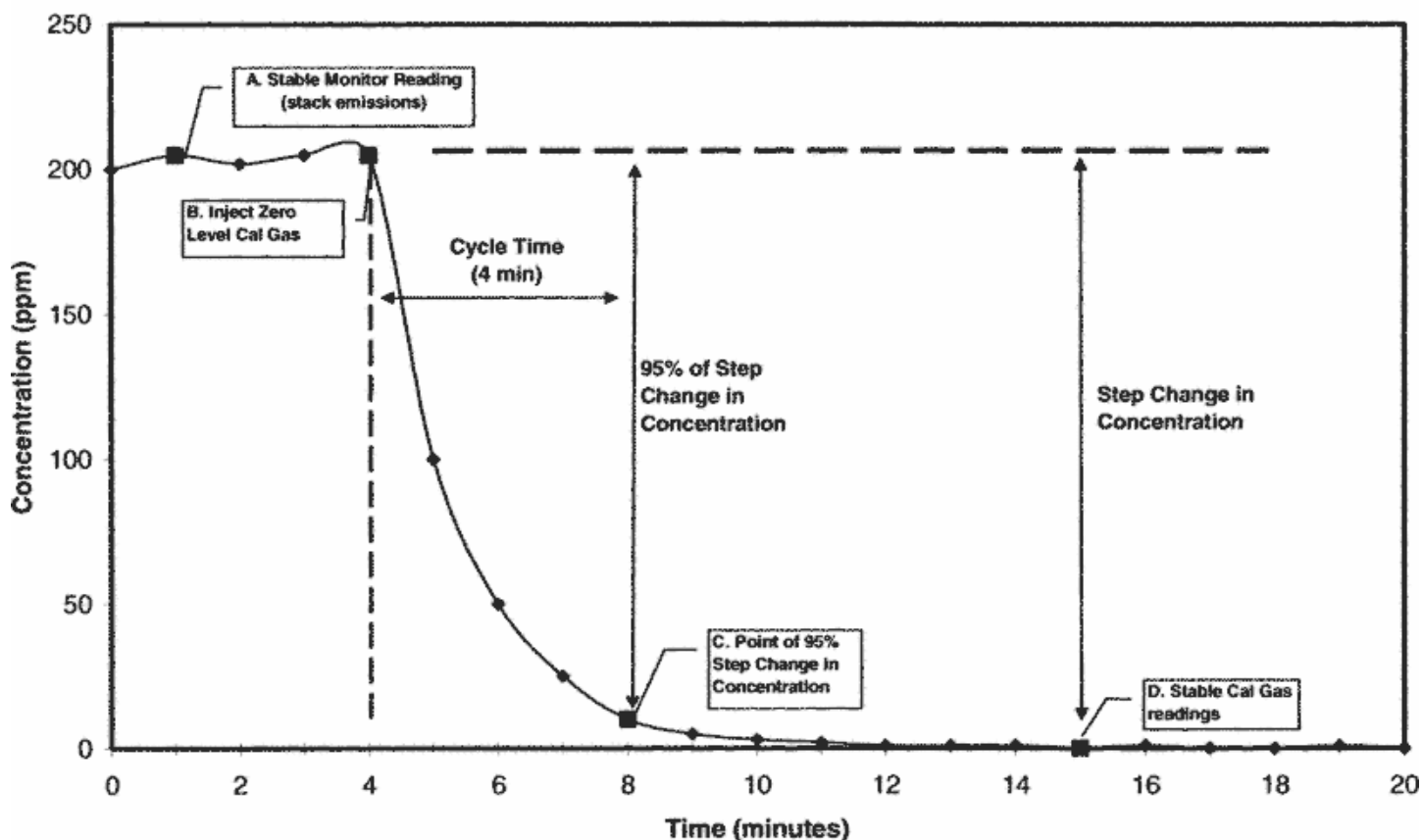


Figure 6b. Downscale Cycle Time Test



- A. To determine the upscale cycle time (Figure 6a), measure the flue gas emissions until the response stabilizes. Record the stabilized value (see section 6.4 of this appendix for the stability criteria).
- B. Inject a high-level calibration gas into the port leading to the calibration cell or thimble (Point B). Allow the analyzer to stabilize. Record the stabilized value.
- C. Determine the step change. The step change is equal to the difference between the final stable calibration gas value (Point D) and the stabilized stack emissions value (Point A).
- D. Take 95% of the step change value and add the result to the stabilized stack emissions value (Point A). Determine the time at which 95% of the step change occurred (Point C).
- E. Calculate the upscale cycle time by subtracting the time at which the calibration gas was injected (Point B) from the time at which 95% of the step change occurred (Point C). In this example, upscale cycle time = $(11 - 5) = 6$ minutes.
- F. To determine the downscale cycle time (Figure 6b) repeat the procedures above, except that a zero gas is injected when the flue gas emissions have stabilized, and 95% of the step change in concentration is subtracted from the stabilized stack emissions value.
- G. Compare the upscale and downscale cycle time values. The longer of these two times is the cycle time for the analyzer.

Editorial Note: For FEDERAL REGISTER citations affecting part 75, Appendix A, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.govinfo.gov.

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

Develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems, excepted monitoring systems approved under appendix D or E to this part, and alternative monitoring systems under subpart E of this part, and their components. At a minimum, include in each QA/QC program a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for each of the following activities. Upon request from regulatory authorities, the source shall make all procedures, maintenance records, and ancillary supporting documentation from the manufacturer (e.g., software coefficients and troubleshooting diagrams) available for review during an audit. Electronic storage of the information in the QA/QC plan is permissible, provided that the information can be made available in hardcopy upon request during an audit.

1.1 Requirements for All Monitoring Systems

1.1.1 Preventive Maintenance

Keep a written record of procedures needed to maintain the monitoring system 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.

1.1.2 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts E, F, and G and appendices D and E to this part, as applicable.

1.1.3 Maintenance Records

Keep a record of all testing, maintenance, or repair activities performed on any monitoring system or component 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's outage period. Additionally, any adjustment that recharacterizes a system's ability to record and report emissions data must be recorded (e.g., changing of flow monitor or moisture monitoring system polynomial coefficients, K factors or mathematical algorithms, changing of temperature and pressure coefficients and dilution ratio settings), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

- 1.1.4 The provisions in section 6.1.2 of appendix A to this part shall apply to the annual RATAs described in § 75.74(c)(2)(ii) and to the semiannual and annual RATAs described in section 2.3 of this appendix.

1.2 Specific Requirements for Continuous Emissions Monitoring Systems

1.2.1 Calibration Error Test and Linearity Check Procedures

Keep a written record of the procedures used for daily calibration error tests and linearity checks (e.g., how gases are to be injected, adjustments of flow rates and pressure, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made). Identify any calibration error test and linearity check procedures specific to the continuous emission monitoring system that vary from the procedures in appendix A to this part.

1.2.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors and other factors affecting calibration of each continuous emission monitoring system.

1.2.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring systems that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.2.4 Parametric Monitoring for Units With Add-on Emission Controls

The owner or operator shall keep a written (or electronic) record including a list of operating parameters for the add-on SO₂ or NO_x emission controls, including parameters in § 75.55(b) or § 75.58(b), as applicable, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The owner or operator shall keep a written (or electronic) record of the parametric monitoring data during each SO₂ or NO_x missing data period.

1.3 Specific Requirements for Excepted Systems Approved Under Appendices D and E

1.3.1 Fuel Flowmeter Accuracy Test Procedures

Keep a written record of the specific fuel flowmeter accuracy test procedures. These may include: standard methods or specifications listed in and of appendix D to this part and incorporated by reference under § 75.6; the procedures of sections 2.1.5.2 or 2.1.7 of appendix D to this part; or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.2 Transducer or Transmitter Accuracy Test Procedures

Keep a written record of the procedures for testing the accuracy of transducers or transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6 of appendix D to this part. These procedures should include a description of equipment used, steps in testing, and frequency of testing.

1.3.3 Fuel Flowmeter, Transducer, or Transmitter Calibration and Maintenance Records

Keep a record of adjustments, maintenance, or repairs performed on the fuel flowmeter monitoring system. Keep records of the data and results for fuel flowmeter accuracy tests and transducer accuracy tests, consistent with appendix D to this part.

1.3.4 Primary Element Inspection Procedures

Keep a written record of the standard operating procedures for inspection of the primary element (i.e., orifice, venturi, or nozzle) of an orifice-, venturi-, or nozzle-type fuel flowmeter. Examples of the types of information to be included are: what to examine on the primary element; how to identify if there is corrosion sufficient to affect the accuracy of the primary element; and what inspection tools (e.g., baroscope), if any, are used.

1.3.5 Fuel Sampling Method and Sample Retention

Keep a written record of the standard procedures used to perform fuel sampling, either by utility personnel or by fuel supply company personnel. These procedures should specify the portion of the ASTM method used, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c). These procedures should describe safeguards for ensuring the availability of an oil sample (e.g., procedure and location for splitting samples, procedure for maintaining sample splits on site, and procedure for transmitting samples to an analytical laboratory). These procedures should identify the ASTM analytical methods used to analyze sulfur content, gross calorific value, and density, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.6 Appendix E Monitoring System Quality Assurance Information

Identify the recommended range of quality assurance- and quality control-related operating parameters. Keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). Keep a written record of the procedures used to perform NO_x emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO_x emission rate testing, including the values of quality assurance parameters specified in section 2.3 of appendix E to this part.

1.4 Requirements for Alternative Systems Approved Under Subpart E

1.4.1 Daily Quality Assurance Tests

Explain how the daily assessment procedures specific to the alternative monitoring system are to be performed.

1.4.2 Daily Quality Assurance Test Adjustments

Explain how each component of the alternative monitoring system will be adjusted in response to the results of the daily assessments.

1.4.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed alternative monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

2. Frequency of Testing

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this appendix in Figure 1.

2.1 Daily Assessments

Perform the following daily assessments to quality-assure the hourly data recorded by the monitoring systems during each period of unit operation, or, for a bypass stack or duct, each period in which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O₂ analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. When two measurement ranges (low and high) are required for a particular parameter, perform sufficient calibration error tests on each range to validate the data recorded on that range, according to the criteria in section 2.1.5 of this appendix.

2.1.1.1 On-line Daily Calibration Error Tests. Except as provided in section 2.1.1.2 of this appendix, all daily calibration error tests must be performed while the unit is in operation at normal, stable conditions (i.e. "on-line").

2.1.1.2 Off-line Daily Calibration Error Tests. Daily calibrations may be performed while the unit is not operating (i.e., "off-line") and may be used to validate data for a monitoring system that meets the following conditions:

- (1) An initial demonstration test of the monitoring system is successfully completed and the results are reported in the quarterly report required under § 75.64 of this part. The initial demonstration test, hereafter called the "off-line calibration demonstration", consists of an off-line calibration error test followed by an on-line calibration error test. Both the off-line and on-line portions of the off-line calibration demonstration must meet the calibration error performance specification in section 3.1 of appendix A of this part. Upon completion of the off-line portion of the demonstration, the zero and upscale monitor responses may be adjusted, but only toward the true values of the calibration gases or reference signals used to perform the test and only in accordance with the routine calibration adjustment procedures specified in the quality control program required under section 1 of appendix B to this part. Once these adjustments are made, no further adjustments may be made to the monitoring system until after completion of the on-line portion of the off-line calibration demonstration. Within 26 clock hours of the completion hour of the off-line portion of the demonstration, the monitoring system must successfully complete the first attempted calibration error test, i.e., the on-line portion of the demonstration.
- (2) For each monitoring system that has passed the off-line calibration demonstration, off-line calibration error tests may be used on a limited basis to validate data, in accordance with paragraph (2) in section 2.1.5.1 of this appendix.

2.1.2 Daily Flow Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2.2 of appendix A of this part while the unit is in operation at normal, stable conditions.

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

- (a) In addition to the daily calibration error tests required under section 2.1.1 of this appendix, a calibration error test of a monitor shall be performed in accordance with section 2.1.1 of this appendix, as follows: whenever a daily calibration error test is failed; whenever a monitoring system is returned to service following repair or corrective maintenance that could affect the monitor's ability to accurately measure and record emissions data; or after making certain calibration adjustments, as described in this section. Except in the case of the routine calibration adjustments described in this section, data from the monitor are considered invalid until the required additional calibration error test has been successfully completed.
- (b) Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments shall be made so as to bring the monitor readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. The EPA recommends that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in appendix A to this part for the pollutant concentration monitor, CO₂ or O₂ monitor, or flow monitor.
- (c) Additional (non-routine) calibration adjustments of a monitor are permitted prior to (but not during) linearity checks and RATAs and at other times, provided that an appropriate technical justification is included in the quality control program required under section 1 of this appendix. The allowable non-routine adjustments are as follows. The owner or operator may physically adjust the calibration of a monitor (e.g., by means of a potentiometer), provided that the post-adjustment zero and upscale responses of the monitor are within the performance specifications of the instrument given in section 3.1 of appendix A to this part. An additional calibration error test is required following such adjustments to verify that the monitor is operating within the performance specifications at both the zero and upscale calibration levels.

2.1.4 Data Validation

- (a) An out-of-control period occurs when the calibration error of an SO₂ or NO_x pollutant concentration monitor exceeds 5.0 percent of the span value, when the calibration error of a CO₂ or O₂ monitor (including O₂ monitors used to measure CO₂ emissions or percent moisture) exceeds 1.0 percent O₂ or CO₂, or when the calibration error of a flow monitor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if $|R-A|$, the absolute value of the difference between the monitor response and the reference value in Equation A-6 of appendix A to this part, is <0.02 inches of water. In addition, an SO₂ or NO_x monitor for which the calibration error exceeds 5.0 percent of the span value shall not be considered out-of-control if $|R-A|$ in Equation A-6 does not

exceed 5.0 ppm (for span values ≤ 50 ppm), or if |R-A|; does not exceed 10.0 ppm (for span values > 50 ppm, but ≤ 200 ppm). The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by § 75.10. A NO_x-diluent CEMS is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

- (b) An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.
- (c) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas from a production site that is not participating in the PGVP, except as provided in § 75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.1.5 Quality Assurance of Data With Respect to Daily Assessments

When a monitoring system passes a daily assessment (i.e., daily calibration error test or daily flow interference check), data from that monitoring system are prospectively validated for 26 clock hours (i.e., 24 hours plus a 2-hour grace period) beginning with the hour in which the test is passed, unless another assessment (i.e. a daily calibration error test, an interference check of a flow monitor, a quarterly linearity check, a quarterly leak check, or a relative accuracy test audit) is failed within the 26-hour period.

2.1.5.1 Data Invalidation with Respect to Daily Assessments. The following specific rules apply to the invalidation of data with respect to daily assessments:

- (1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under section 2.1.5.2 of this appendix), if the required subsequent daily assessment has not been conducted.
- (2) For a monitor that has passed the off-line calibration demonstration, a combination of on-line and off-line calibration error tests may be used to validate data from the monitor, as follows. For a particular unit (or stack) operating hour, data from a monitor may be validated using a successful off-line calibration error test if:
 - (a) An on-line calibration error test has been passed within the previous 26 unit (or stack) operating hours; and

- (b) the 26 clock hour data validation window for the off-line calibration error test has not expired. If either of these conditions is not met, then the data from the monitor are invalid with respect to the daily calibration error test requirement. Data from the monitor shall remain invalid until the appropriate on-line or off-line calibration error test is successfully completed so that both conditions (a) and (b) are met.
- (3) For units with two measurement ranges (low and high) for a particular parameter, when separate analyzers are used for the low and high ranges, a failed or expired calibration on one of the ranges does not affect the quality-assured data status on the other range. For a dual-range analyzer (i.e., a single analyzer with two measurement scales), a failed calibration error test on either the low or high scale results in an out-of-control period for the monitor. Data from the monitor remain invalid until corrective actions are taken and "hands-off" calibration error tests have been passed on both ranges. However, if the most recent calibration error test on the high scale was passed but has expired, while the low scale is up-to-date on its calibration error test requirements (or vice-versa), the expired calibration error test does not affect the quality-assured status of the data recorded on the other scale.

2.1.5.2 Daily Assessment Start-Up Grace Period. For the purpose of quality assuring data with respect to a daily assessment (i.e. a daily calibration error test or a flow interference check), a start-up grace period may apply when a unit begins to operate after a period of non-operation. The start-up grace period for a daily calibration error test is independent of the start-up grace period for a daily flow interference check. To qualify for a start-up grace period for a daily assessment, there are two requirements:

- (1) The unit must have resumed operation after being in outage for 1 or more hours (i.e., the unit must be in a start-up condition) as evidenced by a change in unit operating time from zero in one clock hour to an operating time greater than zero in the next clock hour.
- (2) For the monitoring system to be used to validate data during the grace period, the previous daily assessment of the same kind must have been passed on-line within 26 clock hours prior to the last hour in which the unit operated before the outage. In addition, the monitoring system must be in-control with respect to quarterly and semi-annual or annual assessments.

If both of the above conditions are met, then a start-up grace period of up to 8 clock hours applies, beginning with the first hour of unit operation following the outage. During the start-up grace period, data generated by the monitoring system are considered quality-assured. For each monitoring system, a start-up grace period for a calibration error test or flow interference check ends when either: (1) a daily assessment of the same kind (i.e., calibration error test or flow interference check) is performed; or (2) 8 clock hours have elapsed (starting with the first hour of unit operation following the outage), whichever occurs first.

2.1.6 Data Recording

Record and tabulate all calibration error test data according to month, day, clock-hour, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) Sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2.2 Quarterly Assessments

For each primary and redundant backup monitor or monitoring system, perform the following quarterly assessments. This requirement applies as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Unless a particular monitor (or monitoring range) is exempted under this paragraph or under section 6.2 of appendix A to this part, perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO₂ and NO_x pollutant concentration monitor and each primary and redundant backup CO₂ or O₂ monitor (including O₂ monitors used to measure CO₂ emissions or to continuously monitor moisture) at least once during each QA operating quarter, as defined in § 72.2 of this chapter. For units using both a low and high span value, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. The data validation procedures in section 2.2.3(e) of this appendix shall be followed.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each QA operating quarter. For this test, the unit does not have to be in operation. Conduct the leak checks no less than 30 days apart, to the extent practicable. If a leak check is failed, follow the applicable data validation procedures in section 2.2.3(g) of this appendix.

2.2.3 Data Validation

- (a) A linearity check shall not be commenced if the monitoring system is operating out-of-control with respect to any of the daily or semiannual quality assurance assessments required by sections 2.1 and 2.3 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.
- (b) Each required linearity check shall be done according to paragraph (b)(1), (b)(2) or (b)(3) of this section:

- (1) The linearity check may be done “cold,” i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitor prior to the test.
 - (2) The linearity check may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the various calibration gas levels (zero, low, mid or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor. Trial gas injection runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the linearity check, as necessary, to optimize the performance of the monitor. The trial gas injections need not be reported, provided that they meet the specification for trial gas injections in § 75.20(b)(3)(vii)(E)(1). However, if, for any trial injection, the specification in § 75.20(b)(3)(vii)(E)(1) is not met, the trial injection shall be counted as an aborted linearity check.
 - (3) The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor shall be considered out-of-control from the hour in which the repair, corrective maintenance or reprogramming is commenced until the linearity check has been passed. Alternatively, the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, or reprogramming. If the procedures in § 75.20(b)(3) are used, the words “quality assurance” apply instead of the word “recertification”.
- (c) Once a linearity check has been commenced, the test shall be done hands-off. That is, no adjustments of the monitor are permitted during the linearity test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. If a routine daily calibration error test is performed and passed just prior to a linearity test (or during a linearity test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the linearity test data.
 - (d) If a daily calibration error test is failed during a linearity test period, prior to completing the test, the linearity test must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The linearity test shall not be commenced until the monitor has successfully completed a calibration error test.
 - (e) An out-of-control period occurs when a linearity test is failed (i.e., when the error in linearity at any of the three concentrations in the quarterly linearity check (or any of the six concentrations, when both ranges of a single analyzer with a dual range are tested) exceeds the applicable specification in section 3.2 of appendix A to this part) or when a linearity test is aborted due to a problem with the monitor or monitoring system. For a NO_x-diluent continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceeds the applicable specification in section 3.2 of appendix A to this part or if the linearity test of either component is aborted due to a problem with the monitor. The out-of-control period begins with the hour of the failed or aborted linearity check and ends with the hour of completion of a satisfactory linearity check following corrective action and/or monitor repair, unless the option in paragraph

(b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B). For a dual-range analyzer, “hands-off” linearity checks must be passed on both measurement scales to end the out-of-control period. Note that a monitor shall not be considered out-of-control when a linearity test is aborted for a reason unrelated to the monitor's performance (e.g., a forced unit outage).

- (f) No more than four successive calendar quarters shall elapse after the quarter in which a linearity check of a monitor or monitoring system (or range of a monitor or monitoring system) was last performed without a subsequent linearity test having been conducted. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168 unit operating hour or stack operating hour “grace period” (as provided in section 2.2.4 of this appendix) following the end of the fourth successive elapsed calendar quarter, or data from the CEMS (or range) will become invalid.
- (g) An out-of-control period also occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.
- (h) For each monitoring system, report the results of all completed and partial linearity tests that affect data validation (i.e., all completed, passed linearity checks; all completed, failed linearity checks; and all linearity checks aborted due to a problem with the monitor, including trial gas injections counted as failed test attempts under paragraph (b)(2) of this section or under § 75.20(b)(3)(vii)(F)), in the quarterly report required under § 75.64. Note that linearity attempts which are aborted or invalidated due to problems with the reference calibration gases or due to operational problems with the affected unit(s) need not be reported. Such partial tests do not affect the validation status of emission data recorded by the monitor. A record of all linearity tests, trial gas injections and test attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.
- (i) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas that was not from an EPA Protocol gas production site participating in the PGVP on the date the gas was procured either by the tester or by a reseller that sold to the tester the unaltered EPA Protocol gas, except as provided in § 75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.2.4 Linearity and Leak Check Grace Period

- (a) When a required linearity test or flow monitor leak check has not been completed by the end of the QA operating quarter in which it is due or if, due to infrequent operation of a unit or infrequent use of a required high range of a monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity check of a monitor or monitoring system (or range) was last performed without a subsequent

linearity test having been done, the owner or operator has a grace period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for monitors installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter) in which to perform a linearity test or leak check of that monitor or monitoring system (or range). The grace period begins with the first unit or stack operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity or leak check grace period shall be done in accordance with the applicable provisions in section 2.2.3 of this appendix.

- (b) If, at the end of the 168 unit (or stack) operating hour grace period, the required linearity test or leak check has not been completed, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the monitoring system (or range) remain invalid until the hour of completion of a subsequent successful hands-off linearity test or leak check of the monitor or monitoring system (or range). Note that when a linearity test or a leak check is conducted within a grace period for the purpose of satisfying the linearity test or leak check requirement from a previous QA operating quarter, the results of that linearity test or leak check may only be used to meet the linearity check or leak check requirement of the previous quarter, not the quarter in which the missed linearity test or leak check is completed.

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

- (a) **Applicability and methodology.** Unless exempted from the flow-to-load ratio test under section 7.8 of appendix A to this part, the owner or operator shall, for each flow rate monitoring system installed on each unit, common stack or multiple stack, evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter (as defined in § 72.2 of this chapter). At the end of each QA operating quarter, the owner or operator shall use Equation B-1 to calculate the flow-to-load ratio for every hour during the quarter in which: the unit (or combination of units, for a common stack) operated within ±10.0 percent of L_{avg} , the average load during the most recent normal-load flow RATA; and a quality-assured hourly average flow rate was obtained with a certified flow rate monitor. Alternatively, for the reasons stated in paragraphs (c)(1) through (c)(6) of this section, the owner or operator may exclude from the data analysis certain hours within ±10.0 percent of L_{avg} and may calculate R_h values for only the remaining hours.

$$R_h = \frac{Q_h}{L_h} \times 10^{-5} \quad (\text{Eq. B-1})$$

Where:

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr thermal output).

Q_h = Hourly stack gas volumetric flow rate, as measured by the flow rate monitor, scfh.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

- (1) In Equation B-1, the owner or operator may use either bias-adjusted flow rates or unadjusted flow rates, provided that all of the ratios are calculated the same way. For a common stack, L_h shall be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks or that monitors its emissions in multiple breechings, Q_h will be either the combined hourly volumetric flow rate for all of the stacks or ducts (if the test is done on a unit basis) or the hourly flow rate through each stack individually (if the test is performed separately for each stack). For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, each of which has a certified flow monitor (e.g., a unit with a wet SO₂ scrubber), calculate the hourly flow-to-load ratios separately for each stack. Round off each value of R_h to two decimal places.
- (2) Alternatively, the owner or operator may calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR shall be determined only for those hours in which quality-assured flow rate data and diluent gas (CO₂ or O₂) concentration data are both available from a certified monitor or monitoring system or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \quad (\text{Eq. B-1a})$$

where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or 1000 mmBtu heat input/mmBtu thermal output.

$(\text{Heat Input})_h$ = Hourly heat input, as determined from the quality-assured flow rate and diluent data, using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

- (3) In Equation B-1 a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of $(\text{Heat Input})_h$, provided that all of the heat input rate values are determined in the same manner.
- (4) The owner or operator shall evaluate the calculated hourly flow-to-load ratios (or gross heat rates) as follows. A separate data analysis shall be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis shall be based on a minimum of 168 acceptable recorded hourly average flow rates (i.e., at loads within ± 10 percent of L_{avg}). When two RATA load levels are designated as normal, the analysis shall be performed at the higher load level, unless there are fewer than 168 acceptable data points available at that load level, in which case the analysis shall be performed at the lower

load level. If, for a particular flow monitor, fewer than 168 acceptable hourly flow-to-load ratios (or GHR values) are available at any of the load levels designated as normal, a flow-to-load (or GHR) evaluation is not required for that monitor for that calendar quarter.

- (5) For each flow monitor, use Equation B-2 in this appendix to calculate E_h , the absolute percentage difference between each hourly R_h value and R_{ref} , the reference value of the flow-to-load ratio, as determined in accordance with section 7.7 of appendix A to this part. Note that R_{ref} shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} \times 100 \quad (\text{Eq. B-2})$$

where:

E_h = Absolute percentage difference between the hourly average flow-to-load ratio and the reference value of the flow-to-load ratio at normal load.

R_h = The hourly average flow-to-load ratio, for each flow rate recorded at a load level within ± 10.0 percent of L_{avg} .

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with section 7.7 of appendix A to this part.

- (6) Equation B-2 shall be used in a consistent manner. That is, use R_{ref} and R_h if the flow-to-load ratio is being evaluated, and use $(GHR)_{ref}$ and $(GHR)_h$ if the gross heat rate is being evaluated. Finally, calculate E_f , the arithmetic average of all of the hourly E_h values. The owner or operator shall report the results of each quarterly flow-to-load (or gross heat rate) evaluation, as determined from Equation B-2, in the electronic quarterly report required under § 75.64.

- (b) **Acceptable results.** The results of a quarterly flow-to-load (or gross heat rate) evaluation are acceptable, and no further action is required, if the calculated value of E_f is less than or equal to:

- (1) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥ 60 megawatts (or ≥ 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or
- (2) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥ 60 megawatts (or ≥ 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; or
- (3) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is < 60 megawatts (or < 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or
- (4) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is < 60 megawatts (or < 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations. If E_f is above these limits, the owner or operator shall either: implement Option 1 in section 2.2.5.1 of this appendix; or perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f , after excluding all non-representative hourly flow rates. If E_f is above these limits, the owner or operator

shall either: implement Option 1 in section 2.2.5.1 of this appendix; perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or (if applicable) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f , after excluding all non-representative hourly flow rates, as provided in paragraph (c) of this section.

- (c) **Recalculation of E_f .** If the owner or operator did not exclude any hours within ± 10 percent of L_{avg} from the original data analysis and chooses to recalculate E_f , the flow rates for the following hours are considered non-representative and may be excluded from the data analysis:
- (1) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. For purposes of this determination, the type of fuel is different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) than is the fuel burned during the RATA or if the fuel is a different classification of coal (e.g., bituminous versus sub-bituminous). Also, for units that co-fire different types of fuels, if the reference RATA was done while co-firing, then hours in which a single fuel was combusted may be excluded from the data analysis as different fuel hours (and vice-versa for co-fired hours, if the reference RATA was done while combusting only one type of fuel);
 - (2) For a unit that is equipped with an SO_2 scrubber and which always discharges its flue gases to the atmosphere through a single stack, any hour in which the SO_2 scrubber was bypassed;
 - (3) Any hour in which "ramping" occurred, i.e., the hourly load differed by more than ± 15.0 percent from the load during the preceding hour or the subsequent hour;
 - (4) For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, any hour in which the flue gases were discharged through both stacks;
 - (5) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and
 - (6) If a problem with the accuracy of the flow monitor was discovered during the quarter and was corrected (as evidenced by passing the abbreviated flow-to-load test in section 2.2.5.3 of this appendix), any hour prior to completion of the abbreviated flow-to-load test.
 - (7) After identifying and excluding all non-representative hourly data in accordance with paragraphs (c)(1) through (6) of this section, the owner or operator may analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values must be available to perform the analysis; otherwise, the flow-to-load (or GHR) analysis is not required for that monitor for that calendar quarter.
 - (8) If, after re-analyzing the data, E_f meets the applicable limit in paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section, no further action is required. If, however, E_f is still above the applicable limit, data from the monitor shall be declared out-of-control, beginning with the first unit operating hour following the quarter in which E_f exceeded the applicable limit. Alternatively, if a probationary calibration error test is performed and passed according to § 75.20(b)(3)(ii), data from the monitor may be declared

conditionally valid following the quarter in which E_f exceeded the applicable limit. The owner or operator shall then either implement Option 1 in section 2.2.5.1 of this appendix or Option 2 in section 2.2.5.2 of this appendix.

2.2.5.1 Option 1

Within 14 unit operating days of the end of the calendar quarter for which the E_f value is above the applicable limit, investigate and troubleshoot the applicable flow monitor(s). Evaluate the results of each investigation as follows:

- (a) If the investigation fails to uncover a problem with the flow monitor, a RATA shall be performed in accordance with Option 2 in section 2.2.5.2 of this appendix.
- (b) If a problem with the flow monitor is identified through the investigation (including the need to re-linearize the monitor by changing the polynomial coefficients or K factor(s)), data from the monitor are considered invalid back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. If the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix, all conditionally valid data shall be invalidated, back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. Corrective actions shall be taken. All corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) shall be documented in the operation and maintenance records for the monitor. The owner or operator then shall either complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix, or, if the corrective action taken has required relinearization of the flow monitor, shall perform a 3-load RATA. The conditional data validation procedures in § 75.20(b)(3) may be applied to the 3-load RATA.

2.2.5.2 Option 2

Perform a single-load RATA (at a load designated as normal under section 6.5.2.1 of appendix A to this part) of each flow monitor for which E_f is outside of the applicable limit. If the RATA is passed hands-off, in accordance with section 2.3.2(c) of this appendix, no further action is required and the out-of-control period for the monitor ends at the date and hour of completion of a successful RATA, unless the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix. In that case, all conditionally valid data from the monitor are considered to be quality-assured, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. If the RATA is failed, all data from the monitor shall be invalidated, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. Data from the monitor remain invalid until the required RATA has been passed. Alternatively, following a failed RATA and corrective actions, the conditional data validation procedures of § 75.20(b)(3) may be used until the RATA has been passed. If the corrective actions taken following the failed RATA included adjustment of the polynomial coefficients or K-factor(s) of the flow monitor, a 3-level RATA is required, except as otherwise specified in section 2.3.1.3 of this appendix.

2.2.5.3 Abbreviated Flow-to-Load Test

- (a) The following abbreviated flow-to-load test may be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients or K factor(s)) to demonstrate that the repair, replacement, or other maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until either the hour in which the abbreviated flow-to-load test is passed, or the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. If the latter option is selected, the abbreviated flow-to-load test shall be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor are considered to be conditionally valid (as defined in § 72.2 of this chapter), beginning with the hour of the probationary calibration error test.
- (b) Operate the unit(s) in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal-load flow RATA. To achieve this, it is recommended that the load be held constant to within ± 10.0 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2) concentration be maintained within ± 0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent practicable, use the same combination of units and load levels that were used during the RATA. When the process parameters have been set, record a minimum of six and a maximum of 12 consecutive hourly average flow rates, using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of three and a maximum of 12 consecutive hourly average flow rates are required. Also record the corresponding hourly load values and, if applicable, the hourly diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each hour in the test hour period, using Equation B-1 or B-1a. Determine E_h for each hourly flow-to-load ratio (or GHR), using Equation B-2 of this appendix and then calculate E_f , the arithmetic average of the E_h values.
- (c) The results of the abbreviated flow-to-load test shall be considered acceptable, and no further action is required if the value of E_f does not exceed the applicable limit specified in section 2.2.5 of this appendix. All conditionally valid data recorded by the flow monitor shall be considered quality-assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test (if applicable). However, if E_f is outside the applicable limit, all conditionally valid data recorded by the flow monitor (if applicable) shall be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA is required in accordance with section 2.2.5.2 of this appendix. If the flow monitor must be re-linearized, however, a 3-load RATA is required.

2.3 Semiannual and Annual Assessments

For each primary and redundant backup monitoring system, perform relative accuracy assessments either semiannually or annually, as specified in section 2.3.1.1 or 2.3.1.2 of this appendix, for the type of test and the performance achieved. This requirement applies as of the calendar quarter following the calendar quarter in which the monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

2.3.1 Relative Accuracy Test Audit (RATA)

2.3.1.1 Standard RATA Frequencies

- (a) Except as otherwise specified in § 75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, *i.e.*, once every two successive QA operating quarters (as defined in § 72.2 of this chapter) for each primary and redundant backup SO₂ pollutant concentration monitor, flow monitor, CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions), CO₂ or O₂ diluent monitor used to determine heat input, moisture monitoring system, NO_x concentration monitoring system, or NO_x-diluent CEMS. A calendar quarter that does not qualify as a QA operating quarter shall be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit (or stack) operating hour grace period (as provided in section 2.3.3 of this appendix) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid.
- (b) The relative accuracy test audit frequency of a CEMS may be reduced, as specified in section 2.3.1.2 of this appendix, for primary or redundant backup monitoring systems which qualify for less frequent testing. Perform all required RATAs in accordance with the applicable procedures and provisions in sections 6.5 through 6.5.2.2 of appendix A to this part and sections 2.3.1.3 and 2.3.1.4 of this appendix.

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup SO₂ pollutant concentration monitors, CO₂ pollutant concentration monitors (including O₂ monitors used to determine CO₂ emissions), CO₂ or O₂ diluent monitors used to determine heat input, moisture monitoring systems, NO_x concentration monitoring systems, flow monitors, NO_x-diluent monitoring systems or SO₂-diluent monitoring systems may be performed annually (*i.e.*, once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

- (a) The relative accuracy during the audit of an SO₂ or CO₂ pollutant concentration monitor (including an O₂ pollutant monitor used to measure CO₂ using the procedures in appendix F to this part), or of a CO₂ or O₂ diluent monitor used to

determine heat input, or of a NO_x concentration monitoring system, or of a NO_x-diluent monitoring system, or of an SO₂-diluent continuous emissions monitoring system is ≤ 7.5 percent;

- (b) [Reserved]
- (c) The relative accuracy during the audit of a flow monitor is ≤ 7.5 percent at each operating level tested;
- (d) For low flow (≤ 10.0 fps, as measured by the reference method during the RATA) stacks/ducts, when the flow monitor fails to achieve a relative accuracy ≤ 7.5 percent during the audit, but the monitor mean value, calculated using Equation A-7 in appendix A to this part and converted back to an equivalent velocity in standard feet per second (fps), is within ± 1.5 fps of the reference method mean value, converted to an equivalent velocity in fps;
- (e) For low SO₂ or NO_x emitting units (average SO₂ or NO_x reference method concentrations ≤ 250 ppm) during the RATA, when an SO₂ pollutant concentration monitor or NO_x concentration monitoring system fails to achieve a relative accuracy ≤ 7.5 percent during the audit, but the monitor mean value from the RATA is within ± 12 ppm of the reference method mean value;
- (f) For units with low NO_x emission rates (average NO_x emission rate measured by the reference method during the RATA ≤ 0.200 lb/mmBtu), when a NO_x-diluent continuous emission monitoring system fails to achieve a relative accuracy ≤ 7.5 percent, but the monitoring system mean value from the RATA, calculated using Equation A-7 in appendix A to this part, is within ± 0.015 lb/mmBtu of the reference method mean value;
- (g) [Reserved]
- (h) For a CO₂ or O₂ monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within ± 0.7 percent CO₂ or O₂; and
- (i) When the relative accuracy of a continuous moisture monitoring system is ≤ 7.5 percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within ± 1.0 percent H₂O.

2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements

- (a) For SO₂ pollutant concentration monitors, CO₂ emissions concentration monitors (including O₂ monitors used to determine CO₂ emissions), CO₂ or O₂ diluent monitors used to determine heat input, NO_x concentration monitoring systems, and NO_x-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level (or operating level) designated as normal under section 6.5.2.1(d) of appendix A to this part. If two load levels (or operating levels) are designated as normal, the required RATA(s) may be done at either load level (or operating level).

- (b) For flow monitors installed on peaking units and bypass stacks, and for flow monitors that qualify to perform only single-level RATAs under section 6.5.2(e) of appendix A to this part, all required semiannual or annual relative accuracy test audits shall be single-load (or single-level) audits at the normal load (or operating level), as defined in section 6.5.2.1(d) of appendix A to this part.
- (c) For all other flow monitors, the RATAs shall be performed as follows:
 - (1) An annual 2-load (or 2-level) flow RATA shall be done at the two most frequently used load levels (or operating levels), as determined under section 6.5.2.1(d) of appendix A to this part, or (if applicable) at the operating levels determined under section 6.5.2(e) of appendix A to this part. Alternatively, a 3-load (or 3-level) flow RATA at the low, mid, and high load levels (or operating levels), as defined under section 6.5.2.1(b) of appendix A to this part, may be performed in lieu of the 2-load (or 2-level) annual RATA.
 - (2) If the flow monitor is on a semiannual RATA frequency, 2-load (or 2-level) flow RATAs and single-load (or single-level) flow RATAs at the normal load level (or normal operating level) may be performed alternately.
 - (3) A single-load (or single-level) annual flow RATA may be performed in lieu of the 2-load (or 2-level) RATA if the results of an historical load data analysis show that in the time period extending from the ending date of the last annual flow RATA to a date that is no more than 21 days prior to the date of the current annual flow RATA, the unit (or combination of units, for a common stack) has operated at a single load level (or operating level) (low, mid, or high), for ≥ 85.0 percent of the time. Alternatively, a flow monitor may qualify for a single-load (or single-level) RATA if the 85.0 percent criterion is met in the time period extending from the beginning of the quarter in which the last annual flow RATA was performed through the end of the calendar quarter preceding the quarter of current annual flow RATA.
 - (4) A 3-load (or 3-level) RATA, at the low-, mid-, and high-load levels (or operating levels), as determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once every twenty consecutive calendar quarters, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.
 - (5) A 3-load (or 3-level) RATA is required whenever a flow monitor is re-linearized, *i.e.*, when its polynomial coefficients or K factor(s) are changed, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part. For monitors so exempted under section 6.5.2(b), a single-load flow RATA is required. For monitors so exempted under section 6.5.2(e), either a single-level RATA or a 2-level RATA is required, depending on the number of operating levels documented in the monitoring plan for the unit.
 - (6) For all multi-level flow audits, the audit points at adjacent load levels or at adjacent operating levels (*e.g.*, mid and high) shall be separated by no less than 25.0 percent of the "range of operation," as defined in section 6.5.2.1 of appendix A to this part.

- (d) A RATA of a moisture monitoring system shall be performed whenever the coefficient, K factor or mathematical algorithm determined under section 6.5.7 of appendix A to this part is changed.

2.3.1.4 Number of RATA Attempts

The owner or operator may perform as many RATA attempts as are necessary to achieve the desired relative accuracy test audit frequencies and/or bias adjustment factors. However, the data validation procedures in section 2.3.2 of this appendix must be followed.

2.3.2 Data Validation

- (a) A RATA shall not commence if the monitoring system is operating out-of-control with respect to any of the daily and quarterly quality assurance assessments required by sections 2.1 and 2.2 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.
- (b) Each required RATA shall be done according to paragraphs (b)(1), (b)(2) or (b)(3) of this section:
 - (1) The RATA may be done "cold," i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitoring system prior to the test.
 - (2) The RATA may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the zero and/or upscale calibration gas levels, but no other corrective maintenance, repair, re-linearization or reprogramming of the monitoring system. Trial RATA runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the RATA, as necessary, to optimize the performance of the CEMS. The trial RATA runs need not be reported, provided that they meet the specification for trial RATA runs in § 75.20(b)(3)(vii)(E)(2). However, if, for any trial run, the specification in § 75.20(b)(3)(vii)(E)(2) is not met, the trial run shall be counted as an aborted RATA attempt.
 - (3) The RATA may be done after repair, corrective maintenance, re-linearization or reprogramming of the monitoring system. In this case, the monitoring system shall be considered out-of-control from the hour in which the repair, corrective maintenance, re-linearization or reprogramming is commenced until the RATA has been passed. Alternatively, the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, re-linearization or reprogramming. If the procedures in § 75.20(b)(3) are used, the words "quality assurance" apply instead of the word "recertification."
- (c) Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3

of this appendix. If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the RATA test data. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.

- (d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (*i.e.*, when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed RATA(s) at the other load level(s) (or operating level(s)) are unaffected, unless the monitor's polynomial coefficients or K-factor(s) must be changed to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in section 2.3.1.3 (c)(5) of this appendix.
- (e) For a RATA performed using the option in paragraph (b)(1) or (b)(2) of this section, if the RATA is failed (that is, if the relative accuracy exceeds the applicable specification in section 3.3 of appendix A to this part) or if the RATA is aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in section 3.3 of appendix A to this part. If the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Note that when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (h) of this section), this does not trigger an out-of-control period for the monitoring system.
- (f) For a 2-level or 3-level flow RATA, if, at any load level (or operating level), a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load level (or operating level) must be repeated. The flow monitor is considered out-of-control and data from the monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the passing of a RATA at the failed load level (or operating level), unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Flow RATA(s) that were previously passed at the other load level(s) (or operating level(s)) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the flow monitor is re-linearized, a subsequent 3-load (or 3-level) RATA is required, except as otherwise provided in section 2.3.1.3(c)(5) of this appendix.

- (g) Data validation for failed RATAs for a CO₂ pollutant concentration monitor (or an O₂ monitor used to measure CO₂ emissions), a NO_x pollutant concentration monitor, and a NO_x-diluent monitoring system shall be done according to paragraphs (g)(1) and (g)(2) of this section:
 - (1) For a CO₂ pollutant concentration monitor (or an O₂ monitor used to measure CO₂ emissions) which also serves as the diluent component in a NO_x-diluent monitoring system, if the CO₂ (or O₂) RATA is failed, then both the CO₂ (or O₂) monitor and the associated NO_x-diluent system are considered out-of-control, beginning with the hour of completion of the failed CO₂ (or O₂) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).
 - (2) This paragraph (g)(2) applies only to a NO_x pollutant concentration monitor that serves both as the NO_x component of a NO_x concentration monitoring system (to measure NO_x mass emissions) and as the NO_x component in a NO_x-diluent monitoring system (to measure NO_x emission rate in lb/mmBtu). If the RATA of the NO_x concentration monitoring system is failed, then both the NO_x concentration monitoring system and the associated NO_x-diluent monitoring system are considered out-of-control, beginning with the hour of completion of the failed NO_x concentration RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.7 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).
- (h) For each monitoring system, report the results of all completed and partial RATAs that affect data validation (i.e., all completed, passed RATAs; all completed, failed RATAs; and all RATAs aborted due to a problem with the CEMS, including trial RATA runs counted as failed test attempts under paragraph (b)(2) of this section or under § 75.20(b)(3)(vii)(F)) in the quarterly report required under § 75.64. Note that RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. However, a record of all RATAs, trial RATA runs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.
- (i) Each time that a hands-off RATA of an SO₂ pollutant concentration monitor, a NO_x-diluent monitoring system, a NO_x concentration monitoring system, or a flow monitor is passed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO₂, NO_x, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

- (j) Failure of the bias test does not result in the monitoring system being out-of-control.
- (k) The results of any certification, recertification, diagnostic, or quality assurance test required under this part may not be used to validate the emissions data required under this part, if the test is performed using EPA Protocol gas from a production site that is not participating in the PGVP, except as provided in § 75.21(g)(7) or if the cylinder(s) are analyzed by an independent laboratory and shown to meet the requirements of section 5.1.4(b) of appendix A to this part.

2.3.3 RATA Grace Period

- (a) The owner or operator has a grace period of 720 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 720 consecutive stack operating hours, as defined in § 72.2 of this chapter), in which to complete the required RATA for a particular CEMS whenever:
 - (1) A required RATA has not been performed by the end of the QA operating quarter in which it is due; or
 - (2) A required 3-load flow RATA has not been performed by the end of the calendar quarter in which it is due; or
 - (3) For a unit which is conditionally exempted under § 75.21(a)(7) from the SO₂ RATA requirements of this part, an SO₂ RATA has not been completed by the end of the calendar quarter in which the annual usage of fuel(s) with a sulfur content higher than very low sulfur fuel (as defined in § 72.2 of this chapter) exceeds 480 hours; or
 - (4) Eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due either to infrequent operation of the unit(s) or frequent combustion of very low sulfur fuel, as defined in § 72.2 of this chapter (SO₂ monitors, only), or a combination of these factors.
- (b) Except for SO₂ monitoring system RATAs, the grace period shall begin with the first unit (or stack) operating hour following the calendar quarter in which the required RATA was due. For SO₂ monitor RATAs, the grace period shall begin with the first unit (or stack) operating hour in which fuel with a total sulfur content higher than that of very low sulfur fuel (as defined in § 72.2 of this chapter) is burned in the unit(s), following the quarter in which the required RATA is due. Data validation during a RATA grace period shall be done in accordance with the applicable provisions in section 2.3.2 of this appendix.
- (c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. The deadline for the next test shall be either two QA operating quarters (if a semiannual RATA frequency is obtained) or four QA operating quarters (if an annual RATA frequency is obtained) after the quarter in which the RATA is completed, not to exceed eight calendar quarters.
- (d) When a RATA is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall be determined as follows:

- (1) If the grace period RATA qualifies for a reduced, (i.e., annual), RATA frequency the deadline for the next RATA shall be set at three QA operating quarters after the quarter in which the grace period test is completed.
- (2) If the grace period RATA qualifies for the standard, (i.e., semiannual), RATA frequency the deadline for the next RATA shall be set at two QA operating quarters after the quarter in which the grace period test is completed.
- (3) Notwithstanding these requirements, no more than eight successive calendar quarters shall elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO₂ pollutant concentration monitor, a flow monitor, a NO_x-diluent CEMS, or a NO_x concentration monitoring system used to calculate NO_x mass emissions fails the bias test specified in section 7.6 of appendix A to this part, use the bias adjustment factor given in Equations A-11 and A-12 of appendix A to this part or the allowable alternative BAF specified in section 7.6.5(b) of appendix A of this part, to adjust the monitored data.

2.4 Recertification, Quality Assurance, RATA Frequency and Bias Adjustment Factors (Special Considerations)

- (a) When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with § 75.20(b), a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In all recertifications, a RATA will be one of the required tests; for some recertifications, other tests will also be required. A recertification test may be used to satisfy the quality assurance test requirement of this appendix. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity check is successful, then, unless another such recertification event occurs in that same QA operating quarter, it would not be necessary to perform an additional linearity test of the CEMS in that quarter to meet the quality assurance requirement of section 2.2.1 of this appendix. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this appendix. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in § 75.20(b)(3) shall be followed.
- (b) Except as provided in section 2.3.3 of this appendix, whenever a passing RATA of a gas monitor is performed, or a passing 2-load (or 2-level) RATA or a passing 3-load (or 3-level) RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a recertification requirement or to meet the quality assurance requirements of this appendix, or both), the RATA frequency (semi-annual or annual) shall be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load (or 2-level) and 3-load (or 3-level) flow RATAs, use the highest percentage relative accuracy at any of the loads (or levels) to determine the RATA frequency. The results of a single-load (or single-level)

flow RATA may be used to establish the RATA frequency when the single-load (or single-level) flow RATA is specifically required under section 2.3.1.3(b) of this appendix or when the single-load (or single-level) RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at one load level (or operating level) for ≥ 85.0 percent of the time since the last annual flow RATA. No other single-load (or single-level) flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load (or a 2-level or 3-level) flow RATA may be performed at any time or in place of any required single-load (or single-level) RATA, in order to establish an annual RATA frequency.

2.5 Other Audits

Affected units may be subject to relative accuracy test audits at any time. If a monitor or continuous emission monitoring system fails the relative accuracy test during the audit, the monitor or continuous emission monitoring system shall be considered to be out-of-control beginning with the date and time of completion of the audit, and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an audit, use the bias adjustment factor given by equations A-11 and A-12 in appendix A to this part to adjust the monitored data. Apply this adjustment factor from the date and time of completion of the audit until the date and time of completion of a relative accuracy test audit that does not show bias.

FIGURE 1 TO APPENDIX B OF PART 75—QUALITY ASSURANCE TEST REQUIREMENTS

Test	Basic QA test frequency requirements		
	Daily *	Quarterly *	Semiannual or annual *
Calibration Error Test (2 pt.)	X		
Interference Check (flow)	X		
Flow-to-Load Ratio		X	
Leak Check (DP flow monitors)		X	
Linearity Check * (3 pt.)		X	

* "Daily" means operating days, only. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

¹ Conduct RATA annually (i.e., once every four QA operating quarters) rather than semiannually, if monitor meets accuracy requirements to qualify for less frequent testing.

² For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥ 85.0 percent of the time. A 3-level RATA is required at least once every five years (20 calendar quarters) and whenever a flow monitor is re-characterized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

Test	Basic QA test frequency requirements		
	Daily *	Quarterly *	Semiannual or annual *
RATA (SO ₂ , NO _x , CO ₂ , O ₂ , H ₂ O) ¹			X
RATA (flow) ^{1 2}			X

* "Daily" means operating days, only. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

¹ Conduct RATA annually (i.e., once every four QA operating quarters) rather than semiannually, if monitor meets accuracy requirements to qualify for less frequent testing.

² For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥85.0 percent of the time. A 3-level RATA is required at least once every five years (20 calendar quarters) and whenever a flow monitor is re-characterized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

FIGURE 2 TO APPENDIX B OF PART 75—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual ^W	Annual ^W
SO ₂ or NO _x ^Y	7.5% <RA ≤10.0% or ±15.0 ppm ^X	RA ≤7.5% or ±12.0 ppm ^X .
NO _x -diluent	7.5% <RA ≤10.0% or ±0.020 lb/mmBtu ^X	RA ≤7.5% or ±0.015 lb/mmBtu ^X .
Flow	7.5% <RA ≤10.0% or ±2.0 fps ^X	RA ≤7.5% or ±1.5 fps ^X .
CO ₂ or O ₂	7.5% <RA ≤10.0% or ±1.0% CO ₂ /O ₂ ^X	RA ≤7.5% or ±0.7% CO ₂ /O ₂ ^X .

^W The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO₂ monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2 of this chapter, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed. A 720 operating hour grace period is available if the RATA cannot be completed by the deadline.

^X The difference between monitor and reference method mean values applies to moisture monitors, CO₂, and O₂ monitors, low emitters of SO₂, NO_x, and low flow, only.

^Y A NO_x concentration monitoring system used to determine NO_x mass emissions under § 75.71.

RATA	Semiannual ^W	Annual ^W
Moisture	7.5% <RA ≤10.0% or ±1.5% H ₂ O ^X	RA ≤7.5% or ±1.0% H ₂ O ^X .

^W The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO₂ monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2 of this chapter, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed. A 720 operating hour grace period is available if the RATA cannot be completed by the deadline.

^X The difference between monitor and reference method mean values applies to moisture monitors, CO₂, and O₂ monitors, low emitters of SO₂, NO_x, and low flow, only.

^Y A NO_x concentration monitoring system used to determine NO_x mass emissions under § 75.71.

40 CFR Appendix-A-to-Part-75 G. (enhanced display)

Value – NIST Value) / NIST Value

and regarding the performance of any EPA Protocol gas production site inadvertently not included in the audit. Any accuracy assessment based on a single audit is a snapshot of the process being measured. These results should not be regarded as a final statement on the accuracy of EPA Protocol gas production. EPA Protocol gas production should be used as a general indicator of the current status of the accuracy of EPA Protocol gases as a whole. However, individual results should not be used as definitive indicators of the analytical capabilities of individual producers. EPA presents this information without assigning a rating to the gas production site, who is the best, who is approved, or is not approved and specifically does not endorse any particular vendor.

orders with more than one component plus balance gas, change the title appropriately, e.g., "FIGURE 3 TO APPENDIX B OF ORDER PLUS BALANCE GAS CYLINDERS ..." and add appropriate columns to Figure 3 for the additional components following used in the columns for SO₂ above.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26546, 26571, May 17, 1995; 61 FR 59165, Nov. 20, 1996; 64 FR 28644, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40456, 40457, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 67 FR 57274, Sept. 9, 2002; 70 FR 28693, May 18, 2005; 72 FR 51528, Sept. 7, 2007; 73 FR 4367, Jan. 24, 2008; 76 FR 17321, Mar. 28, 2011]

Appendix C to Part 75—Missing Data Estimation Procedures

1. Parametric Monitoring Procedure for Missing SO₂ Concentration or NO_x Emission Rate Data

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO₂ or NO_x emission controls and SO₂ pollutant concentration monitors and/or NO_x continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO₂ of postcombustion NO_x emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO₂ emissions or average emission rate of NO_x discharged to the atmosphere. After approval by the Administrator, such method or model may be used for filling in missing SO₂ concentration or NO_x emission rate data when data from the outlet SO₂ pollutant concentration monitor or outlet NO_x continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

1.2 Petition Requirements

Continuously monitor, determine, and record hourly averages of the estimated SO₂ or NO_x removal efficiency and of the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. Measure the SO₂ concentration or NO_x emission rate, removal efficiency of the add-on emission controls, and the parameters for at least 2160 unit operating hours. Provide information for all expected operating conditions and removal efficiencies. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2 data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO₂ concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO₂ concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO₂ control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

1.2.4 Parameters for Post-Combustion NO_x Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).

1.2.4.5 Inlet and outlet NO_x emission rate as determined by the NO_x continuous emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

1.3 Correlation of Emissions With Parameters

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO₂ or post-combustion NO_x emission controls under varying unit operating loads. Equations 1-7 in § 75.15 may be used to estimate the percent removal efficiency of the SO₂ emission controls on an hourly basis.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO₂ emission controls or post-combustion NO_x emission controls, along with the SO₂ pollutant concentration monitor and NO_x continuous emission monitoring system values for varying unit load ranges.

For NO_x emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

1.4 Calculations

- 1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO₂ pollutant concentration monitor data.

$$M_o = I_c (1-E)$$

(Eq. C-1)

where,

M_o = Substitute data for outlet SO₂ concentration, ppm.

I_c = Recorded inlet SO₂ concentration, ppm.

E = Removal efficiency of SO₂ emission controls as determined by the correlation procedure described in section 1.3 of this appendix.

- 1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

$$M_o = I_c (1-E)$$

(Eq. C-2)

where,

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in section 1.3 of this appendix.

1.5 Missing Data

- 1.5.1 If both the inlet and the outlet SO₂ pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO₂ concentration recorded by the inlet SO₂ pollutant concentration monitor during the previous 720 quality-assured monitor operating hours to substitute for the inlet SO₂ concentration in equation C-1 of this appendix.
- 1.5.2 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO_x emission rate for the corresponding unit load recorded by the NO_x continuous emission monitoring system at the inlet during the previous 2160 quality-assured monitor operating hours to substitute for the inlet NO_x emission rate in equation C-2 of this appendix.

1.6 Application

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO₂ concentration or NO_x emission rate data using the established criteria and information identified above. DO not use this procedure until approved by the Administrator.

2. Load-based Procedure for Missing Flow Rate, NO_x Concentration, and NO_x Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_x emission rate (in lb/mmBtu) from NO_x-diluent continuous emission monitoring systems, and NO_x concentration data (in ppm) from NO_x concentration monitoring systems used to determine NO_x mass emissions.

2.2 Procedure

- 2.2.1 For a single unit, establish ten operating load ranges defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MWge), as shown in Table C-1. (Do not use integrated hourly gross load in MW-hr.) For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO_x) may be broken down into 20 operating load ranges in increments of 5.0 percent of the combined maximum hourly average gross load of all units utilizing the common stack. If this option is selected, the twentieth (uppermost) operating load range shall include all values greater than 95.0 percent of the maximum hourly average gross load. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in

pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

**TABLE C-1—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED
SUBSTITUTION DATA PROCEDURES**

Operating load range	Percent of maximum hourly gross load or maximum hourly gross steam load (percent)
1	0-10
2	>10-20
3	>20-30
4	>30-40
5	>40-50
6	>50-60
7	>60-70
8	>70-80
9	>80-90
10	>90

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x-diluent continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)), for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x-diluent continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)) and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_x data within each identified load range during the shorter of: (a) the previous 2,160 quality-assured monitor operating hours (on a rolling basis), or (b) all previous quality-assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

- 2.2.3.5 Average of the hourly NO_x emission rate, in lb/mmBtu, reported by a NO_x continuous emission monitoring system.
- 2.2.3.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu.
- 2.2.3.7 The 95th percentile value of hourly NO_x emission rates, in lb/mmBtu.
- 2.2.3.8 The maximum value of hourly NO_x emission rates, in lb/mmBtu.
- 2.2.3.9 Average of the hourly NO_x pollutant concentrations, in ppm, reported by a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2).
- 2.2.3.10 The 90th percentile value of hourly NO_x pollutant concentration, in ppm.
- 2.2.3.11 The 95th percentile value of hourly NO_x pollutant concentration, in ppm.
- 2.2.3.12 The maximum value of hourly NO_x pollutant concentration, in ppm.
- 2.2.4 Calculate all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by this procedure using bias adjusted values in the load ranges.
- 2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_x-diluent continuous emission monitoring system (and/or the NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2)), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.
- 2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data (and where applicable, NO_x concentration data) according to the procedures in subpart D of this part.

3. Non-load-based Procedure for Missing Flow Rate, NO_x Concentration, and NO_x Emission Rate Data (Optional)

3.1 Applicability

For affected units that do not produce electrical output in megawatts or thermal output in klb/hr of steam, this procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_x emission rate (in lb/mmBtu) from NO_x-diluent continuous emission monitoring systems, and NO_x concentration data (in ppm) from NO_x concentration monitoring systems used to determine NO_x mass emissions.

3.2 Procedure

- 3.2.1 For each monitored parameter (flow rate, NO_x emission rate, or NO_x concentration), establish at least two, but no more than ten operational bins, corresponding to various operating conditions and parameters (or combinations of these) that affect volumetric flow rate or NO_x emissions. Include a complete description of each operational bin in the hardcopy portion of the monitoring plan required under § 75.53(e)(2), identifying the unique combination of parameters and operating conditions associated with the bin and explaining the relationship between these parameters and conditions and the magnitude of the stack gas flow rate or NO_x emissions.

Assign a unique number, 1 through 10, to each operational bin. Examples of conditions and parameters that may be used to define operational bins include unit heat input, type of fuel combusted, specific stages of an industrial process, or (for common stacks), the particular combination of units that are in operation.

- 3.2.2 In the electronic quarterly report required under § 75.64, indicate for each hour of unit operation the operational bin associated with the NO_x or flow rate data, by recording the number assigned to the bin under section 3.2.1 of this appendix.
- 3.2.3 The data acquisition and handling system must be capable of properly identifying and recording the operational bin number for each unit operating hour. The DAHS must also be capable of calculating and recording the following information (as applicable) for each unit operating hour of missing flow or NO_x data within each identified operational bin during the shorter of:
- (a) The previous 2,160 quality-assured monitor operating hours (on a rolling basis), or
 - (b) All previous quality-assured monitor operating hours in the previous 3 years:
- 3.2.3.1 Average of the hourly flow rates reported by a flow monitor (scfh).
 - 3.2.3.2 The 90th percentile value of hourly flow rates (scfh).
 - 3.2.3.3 The 95th percentile value of hourly flow rates (scfh).
 - 3.2.3.4 The maximum value of hourly flow rates (scfh).
 - 3.2.3.5 Average of the hourly NO_x emission rates, in lb/mmBtu, reported by a NO_x-diluent continuous emission monitoring system.
 - 3.2.3.6 The 90th percentile value of hourly NO_x emission rates (lb/mmBtu).
 - 3.2.3.7 The 95th percentile value of hourly NO_x emission rates (lb/mmBtu).
 - 3.2.3.8 The maximum value of hourly NO_x emission rates, in (lb/mmBtu).
 - 3.2.3.9 Average of the hourly NO_x pollutant concentrations (ppm), reported by a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2).
 - 3.2.3.10 The 90th percentile value of hourly NO_x pollutant concentration (ppm).
 - 3.2.3.11 The 95th percentile value of hourly NO_x pollutant concentration (ppm).
 - 3.2.3.12 The maximum value of hourly NO_x pollutant concentration (ppm).
- 3.2.4 When a bias adjustment is necessary for the flow monitor and/or the NO_x-diluent continuous emission monitoring system (and/or the NO_x concentration monitoring system), apply the bias adjustment factor to all data values placed in the operational bins.
- 3.2.5 Calculate all CEMS data averages, maximum values, and percentile values determined by this procedure using bias-adjusted values.
- 3.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data (and where applicable, NO_x concentration data) according to the procedures in subpart D of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26547, 26548, May 17, 1995; 63 FR 57313, Oct. 27, 1998; 64 FR 28652, May 26, 1999; 67 FR 40459, June 12, 2002]

Appendix D to Part 75—Optional SO₂ Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1. Applicability

- 1.1 This protocol may be used in lieu of continuous SO₂ pollutant concentration and flow monitors for the purpose of determining hourly SO₂ mass emissions and heat input from: gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter. Section 2.1 of this appendix provides procedures for measuring oil or gaseous fuel flow using a fuel flowmeter, section 2.2 of this appendix provides procedures for conducting oil sampling and analysis to determine sulfur content and gross calorific value (GCV) of fuel oil, and section 2.3 of this appendix provides procedures for determining the sulfur content and GCV of gaseous fuels.
- 1.2 Pursuant to the procedures in § 75.20, complete all testing requirements to certify use of this protocol in lieu of a flow monitor and an SO₂ continuous emission monitoring system. Complete all testing requirements no later than the applicable deadline specified in § 75.4. Apply to the Administrator for initial certification to use this protocol no later than 45 days after the completion of all certification tests.

2. Procedure

2.1 Fuel Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided in section 2.1.4 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

- 2.1.1 Measure the flow rate of each fuel entering and being combusted by the unit. If, on an annual basis, more than 5.0 percent of the fuel from the main pipe is diverted from the unit without being burned and that diversion occurs downstream of the fuel flowmeter, an additional in-line fuel flowmeter is required to account for the unburned fuel. In this case, record the flow rate of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit. However, the additional fuel flowmeter is not required if, on an annual basis, the total amount of fuel diverted away from the unit, expressed as a percentage of the total annual fuel usage by the unit is demonstrated to be less than or equal to 5.0 percent. The owner or operator may make this demonstration in the following manner:
 - 2.1.1.1 For existing units with fuel usage data from fuel flowmeters, if data are submitted from a previous year demonstrating that the total diverted yearly fuel does not exceed 5% of the total fuel used; or

- 2.1.1.2 For new units which do not have historical data, if a letter is submitted signed by the designated representative certifying that, in the future, the diverted fuel will not exceed 5.0% of the total annual fuel usage; or
- 2.1.1.3 By using a method approved by the Administrator under § 75.66(d).
- 2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (as defined in § 72.2). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix shall not apply to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program, unless both of the following are true: all of the units served by the common pipe are affected units, and all of the units have similar efficiencies. When a fuel flowmeter is installed in a common pipe header, proceed as follows:
 - 2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO₂ mass emissions (Acid Rain Program units only) for the affected units for recordkeeping and compliance purposes; and
 - 2.1.2.2 Apportion the heat input rate measured at the common pipe to the individual units, using Equation F-21a, F-21b, or F-21d in appendix F to this part.
- 2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow rate of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

2.1.4 Situations in Which Certified Flowmeter is Not Required

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition, a gas-fired unit that uses oil solely for start-up or burner ignition, or an oil-fired unit that uses a different grade of oil solely for start-up or burner ignition, a fuel flowmeter for the start-up fuel is permitted but not required. Estimate the volume of oil combusted for each start-up or ignition either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of sections 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

2.1.4.2 Gas or Oil Flowmeter Used for Commercial Billing

A gas or oil flowmeter used for commercial billing of natural gas or oil may be used to measure, record, and report hourly fuel flow rate. A gas or oil flowmeter used for commercial billing of natural gas or oil is not required to meet the certification requirements of section 2.1.5 of this appendix or the quality assurance requirements of section 2.1.6 of this appendix under the following circumstances:

- (a) The gas or oil flowmeter is used for commercial billing under a contract, provided that the company providing the gas or oil under the contract and each unit combusting the gas or oil do not have any common owners and are not owned by subsidiaries or affiliates of the same company;
- (b) The designated representative reports hourly records of gas or oil flow rate, heat input rate, and emissions due to combustion of natural gas or oil;
- (c) The designated representative also reports hourly records of heat input rate for each unit, if the gas or oil flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix;
- (d) The designated representative reports hourly records directly from the gas or oil flowmeter used for commercial billing if these records are the values used, without adjustment, for commercial billing, or reports hourly records using the missing data procedures of section 2.4 of this appendix if these records are not the values used, without adjustment, for commercial billing; and
- (e) The designated representative identifies the gas or oil flowmeter in the unit's monitoring plan.

2.1.4.3 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available is exempt from certifying a fuel flowmeter for use during combustion of the emergency fuel. During any hour in which the emergency fuel is combusted, report the hourly heat input to be the maximum rated heat input of the unit for the fuel. Use the maximum potential sulfur content for the fuel (from Table D-6 of this appendix) and the fuel flow rate corresponding to the maximum hourly heat input to calculate the hourly SO₂ mass emission rate, using Equations D-2 through D-4 (as applicable). Alternatively, if a certified fuel flowmeter is available for the emergency fuel, you may use the measured hourly fuel flow rates in the calculations. Also, if daily samples or weekly composite samples (fuel oil, only) of the fuel's total sulfur content, GCV, and (if applicable) density are taken during the combustion of the emergency fuel, as described in section 2.2 or 2.3 of this appendix, the sample results may be used to calculate the hourly SO₂ emissions and heat input rates, in lieu of using maximum potential values. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

2.1.5 Initial Certification Requirement for all Fuel Flowmeters

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flowmeter) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flowmeters, only) or by measurement under laboratory conditions; by

the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined under section 2.1.5.2 of this appendix by in-line comparison against a reference flowmeter.

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters; American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME-MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters; ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters; ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles; ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, Section 3—Small Volume Provers, First Edition, July 1988, Reaffirmed October 1993, and Section 5—Master-Meter Provers, Second Edition, May 2000; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005; or ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for all other flowmeter types (all incorporated by reference under § 75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under § 75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2

- (a) Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under § 75.66 (all standards incorporated by reference under § 75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a

period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

- (1) Normal full unit operating load,
 - (2) Normal minimum unit operating load,
 - (3) A load point approximately equally spaced between the full and minimum unit operating loads, and
- (b) Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100 \quad (\text{Eq. D-1})$$

Where:

ACC = Flowmeter accuracy at a particular load level, as a percentage of the upper range value.

R = Average of the three flow measurements of the reference flowmeter.

A = Average of the three measurements of the flowmeter being tested.

URV = Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

- (c) Notwithstanding the requirement for calibration of the reference flowmeter within 365 days prior to an accuracy test, when an in-place reference meter or prover is used for quality assurance under section 2.1.6 of this appendix, the reference meter calibration requirement may be waived if, during the previous in-place accuracy test with that reference meter, the reference flowmeter and the flowmeter being tested agreed to within ± 1.0 percent of each other at all levels tested. This exception to calibration and flowmeter accuracy testing requirements for the reference flowmeter shall apply for periods of no longer than five consecutive years (i.e., 20 consecutive calendar quarters).
- 2.1.5.3 If the flowmeter accuracy exceeds the specification in section 2.1.5 of this appendix, the flowmeter does not qualify for use for this appendix. Either recalibrate the flowmeter until the flowmeter accuracy is within the performance specification, or replace the flowmeter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix until quality-assured fuel flow data become available.

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section 2.1.5.2 of this appendix or flow rate from a procedure performed according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests in a manner consistent with Table D-1.

TABLE D-1—TABLE OF FLOWMETER ACCURACY RESULTS

Test number:_____ Test completion date ¹:_____ Test completion time

¹:_____

Reinstallation date ² (for testing under 2.1.5.1 only):_____ Reinstallation time

²:_____

Unit or pipe ID: Component/System ID:

Flowmeter serial number: Upper range value:

Units of measure for flowmeter and reference flow readings:

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
Low (Minimum) level ____ percent ³ of URV	1				
	2				
	3				
	Average				
Mid-level ____ percent ³ of URV	1				
	2				
	3				
	Average				
High (Maximum) level ____ percent ³ of URV	1				
	2				
	3				

¹ Report the date, hour, and minute that all test runs were completed.

² For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.

³ It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
	Average				

¹ Report the date, hour, and minute that all test runs were completed.

² For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.

³ It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

2.1.6 Quality Assurance

- (a) Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters, as defined in § 72.2 of this chapter, thereafter. Notwithstanding these requirements, no more than 20 successive calendar quarters shall elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test having been conducted. Test the flowmeter accuracy more frequently if required by manufacturer specifications.
- (b) Except for orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy testing using the procedures in either section 2.1.5.1 or section 2.1.5.2 of this appendix. Each fuel flowmeter must meet the accuracy specification in section 2.1.5 of this appendix.
- (c) For orifice-, nozzle-, and venturi-type flowmeters, either perform the required flowmeter accuracy testing using the procedures in section 2.1.5.2 of this appendix or perform a transmitter accuracy test for the initial certification and once every four fuel flowmeter QA operating quarters thereafter. Perform a primary element visual inspection for the initial certification and once every 12 calendar quarters thereafter, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic quality assurance.
- (d) Notwithstanding the requirements of this section, if the procedures of section 2.1.7 (fuel flow-to-load test) of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or (if applicable) transmitter accuracy test and primary element inspection, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or (if applicable) transmitter accuracy test and primary element inspection.
- (e) When accuracy testing of the orifice, nozzle, or venturi meter is performed according to section 2.1.5.2 of this appendix, record the information displayed in Table D-1 in this section. At a minimum, record the overall accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

- (f) Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the emissions report for the quarter in which the quality assurance tests are performed, using the electronic format specified by the Administrator under § 75.64.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

- (a) Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other upscale levels (e.g., “mid” and “high”), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented. For temperature transmitters, the zero and upscale levels may correspond to fixed reference points, such as the freezing point or boiling point of water.
- (b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \quad (\text{Eq. D-1a})$$

Where:

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.

R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).

T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

- (c) If each transmitter or transducer meets an accuracy of 1.0 percent of its full-scale range at each level tested, the fuel flowmeter accuracy of 2.0 percent is considered to be met at all levels. If, however, one or more of the transmitters or transducers does not meet an accuracy of 1.0 percent of full-scale at a particular level, then the owner or operator may demonstrate that the fuel flowmeter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flowmeter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flowmeter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flowmeter accuracy requirement is considered to be met for that level.

2.1.6.2 Recordkeeping for Transmitter or Transducer Accuracy Results

- (a)
- Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection.

TABLE D-2—TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

Test number:_____ Test completion date: _____ Unit or pipe ID: _____

Flowmeter serial number: Component/System ID:

Full-scale value: Units of measure: ³

Transducer/Transmitter Type (check one):

___ Differential Pressure

___ Static Pressure

___ Temperature

Measurement level (percent of full-scale)	Run number (if multiple runs) ²	Run time (HHMM)	Transmitter/transducer input (pre-calibration)	Expected transmitter/transducer output (reference)	Actual transmitter/transducer output ³	Percent accuracy (percent of full-scale)
Low (Minimum) level ___ percent ¹ of full-scale Mid-level ___ percent ¹ of full-scale (If tested at more than 3 levels)						

¹ At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.

² It is required to test at least once at each level.

³ Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H₂ O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

Measurement level (percent of full-scale)	Run number (if multiple runs) ²	Run time (HHMM)	Transmitter/transducer input (pre-calibration)	Expected transmitter/transducer output (reference)	Actual transmitter/transducer output ³	Percent accuracy (percent of full-scale)
2nd Mid-level ____ percent ¹ of full-scale (If tested at more than 3 levels)						
3rd Mid-level ____ percent ¹ of full-scale						
High (Maximum) level ____ percent ¹ of full-scale						

¹ At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.

² It is required to test at least once at each level.

³ Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H₂O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

(b)-(c) [Reserved]

2.1.6.3 Failure of Transducer(s) or Transmitter(s)

If, during a transmitter or transducer accuracy test conducted according to section 2.1.6.1 of this appendix, the flowmeter accuracy specification of 2.0 percent is not met at any of the levels tested, repair or replace transmitter(s) or transducer(s) as necessary until the flowmeter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels, to ensure that the flowmeter accuracy specification is met at each level). The fuel flowmeter is "out-of-control" and data from the flowmeter are considered invalid, beginning with the date and hour of the failed accuracy test and continuing until the date and hour of completion of a successful transmitter or transducer accuracy test at all levels. In addition, if, during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter shall be considered invalid from the hour of the transmitter or transducer failure until the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel

flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix and § 75.59.

2.1.6.4 Primary Element Inspection

- (a) Conduct a visual inspection of the orifice, nozzle, or venturi meter at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi meter to at least once every twenty calendar quarters. The inspection may be performed using a baroscope. If the visual inspection is failed (if the orifice, nozzle, or venturi meter has become damaged or corroded), then:
 - (1) Replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6). If the primary element size is changed, also calibrate the transmitters or transducers, consistent with the new primary element size;
 - (2) Replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or
 - (3) Restore the damaged or corroded primary element to “as new” condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); and retest the transmitters or transducers prior to providing quality-assured data from the flowmeter.
- (b) Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when:
 - (1) The damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and, if applicable, the transmitters have been successfully recalibrated;
 - (2) The damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this appendix, using the procedures of section 2.1.5.2 of this appendix; or
 - (3) The restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC-3M-1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and its transmitters or transducers are retested to meet the accuracy specification in section 2.1.6.1 of this appendix.

- (c) During each period of invalid fuel flowmeter data described in paragraph (b) of this section, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.4 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168-hour baseline data requirement of section 2.1.7.1 of this appendix has been met. If, following a flowmeter accuracy test or (if applicable) a flowmeter transmitter test and primary element inspection, the procedures of this section are performed during each subsequent fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.4 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or (if applicable) a transmitter accuracy test and a primary element inspection, are conducted. Notwithstanding the requirements of § 75.57(a), when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.4 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

- (a) Determine R_{base} , the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.4 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality-assured fuel flowmeter data. Baseline data collection shall begin with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (e.g., only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude as non-representative any hour in which the unit is "ramping" up or down, (i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour) and may exclude any hour in which the unit load is in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in this lower 25.0 percent of the range is considered normal for the unit). The baseline data must be obtained no later than the end of the fourth calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. For orifice-, nozzle-, and venturi-type

fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.4 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the fourth calendar quarter following the calendar quarter in which both procedures were completed. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{\text{base}} = \frac{Q_{\text{base}}}{L_{\text{avg}}} \quad (\text{Eq. D-1b})$$

where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe, 100 scfh/klb per hour steam load, or 100 scfh/mmBtu per hour thermal output for gas-firing; (lb/hr)/MWe, (lb/hr)/klb per hour steam load, or (lb/hr)/mmBtu per hour thermal output for oil-firing.

Q_{base} = Arithmetic average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

L_{avg} = Arithmetic average unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

- (b) In Equation D-1b, for a fuel flowmeter installed on a common pipe header, L_{avg} is the sum of the operating loads of all units that received fuel through the common pipe header during the baseline period, divided by the total number of hours of fuel flow rate data collected during the baseline period. For a unit that receives the same type of fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates during the baseline period from all of the pipes, divided by the total number of hours of fuel flow rate data collected during the baseline period. Round off the value of R_{base} to the nearest tenth.
- (c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base} . The baseline value of the GHR, GHR_{base} , shall be determined as follows:

$$(\text{GHR})_{\text{base}} = \frac{(\text{Heat Input})_{\text{avg}}}{L_{\text{avg}}} \times 1000 \quad (\text{Eq. D-1c})$$

Where:

$(\text{GHR})_{\text{base}}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh, Btu/lb steam load, or 1000mmBtu heat input/mmBtu thermal output.

$(\text{Heat Input})_{\text{avg}}$ = Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the average fuel flow rate and the fuel GCV in the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg} = Average (mean) unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

- (d) Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under § 75.64.
- (e) If a unit co-fires different fuels (e.g., oil and natural gas) as its normal mode of operation, the gross heat rate option in paragraph (c) of this section may be used to determine a value of $(GHR)_{base}$, as follows. Derive the baseline data during co-fired hours. Then, use Equation D-1c to calculate $(GHR)_{base}$, making sure that each hourly unit heat input rate used to calculate $(Heat\ Input)_{avg}$ includes the contribution of each type of fuel.

2.1.7.2 Data Preparation and Analysis

- (a) Evaluate the fuel flow rate-to-load ratio (or GHR) for each fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter. At the end of each fuel flowmeter QA operating quarter, use Equation D-1d in this appendix to calculate R_h , the hourly fuel flow-to-load ratio, for every quality-assured hourly average fuel flow rate obtained with a certified fuel flowmeter. Alternatively, the owner or operator may exclude non-representative hours from the data analysis, as described in section 2.1.7.3 of this appendix, prior to calculating the values of R_h .

$$R_h = \frac{Q_h}{L_h} \quad (\text{Eq. D-1d})$$

where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, (lb/hr)/1000 lb/hr of steam load, 100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output).

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

- (b) For a fuel flowmeter installed on a common pipe header, L_h shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives the same type of fuel through multiple pipes, Q_h will be the sum of the fuel flow rates from all of the pipes. Round off each value of R_h to the nearest tenth.
- (c) Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(Heat\ Input)_h}{L_h} \times 1000 \quad (\text{Eq. D-1e})$$

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output.

$(Heat\ Input)_h$ = Hourly heat input rate, as determined using the hourly fuel flow rate and the fuel GCV in the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

- (d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows.
 - (1) Perform a separate data analysis for each fuel flowmeter system following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter system, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, or, if the baseline data collection period is still in progress at the end of the quarter and fewer than four calendar quarters have elapsed since the quarter in which the last successful fuel flowmeter system accuracy test was performed, a flow-to-load (or GHR) evaluation is not required for that flowmeter system for that calendar quarter. A one-quarter extension of the deadline for the next fuel flowmeter system accuracy test may be claimed for a quarter in which there is insufficient hourly data available to analyze or a quarter that ends with the baseline data collection period still in progress.
 - (2) For a unit that normally co-fires different types of fuel (e.g., oil and natural gas), include the contribution of each type of fuel in the value of $(Heat\ Input)_h$, when using Equation D-1e.
- (e) For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D-1f.

$$\%D_h = \frac{|R_{base} - R_h|}{R_{base}} \times 100 \quad (\text{Eq. D-1f})$$

Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

- (f) Consistently use R_{base} and R_h in Equation D-1f if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D-1f if the gross heat rate is being evaluated.
- (g) Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D-1g, as follows:

$$E_f = \sum_{h=1}^q \frac{\%D_h}{q} \quad (\text{Eq. D-1g})$$

Where:

E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

- (h) When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤ 50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent. For units that normally co-fire different types of fuel, if the GHR option is used, apply the test results to each fuel flowmeter system used during the quarter.

2.1.7.3 Optional Data Exclusions

- (a) If E_f is outside the limits in section 2.1.7.2(h) of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and may identify and exclude fuel flow-to-load ratios or GHR values for any non-representative hours, provided that such data exclusions were not previously made under section 2.1.7.2(a) of this appendix. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative:
 - (1) For units that do not normally co-fire fuels, any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or
 - (2) Any hour for which the load differed by more than ± 15.0 percent from the load during either the preceding hour or the subsequent hour; or
 - (3) For units that normally co-fire different fuels, any hour in which the unit burned only one type of fuel; or
 - (4) Any hour for which the unit load was in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in the lower 25.0 percent of the range is considered normal for the unit).

- (b) After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time. If fewer than 168 hourly fuel flow-to-load ratio or GHR values remain after the allowable data exclusions, a fuel flow-to-load ratio or GHR analysis is not required for that quarter, and a one-quarter extension of the fuel flowmeter accuracy test deadline may be claimed.

2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

- (a) If E_f is outside the applicable limit in section 2.1.7.2(h) of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2 of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6-to-12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.4 of this appendix, and repair or replace the primary element, as necessary.
- (b) Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality-assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality-assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two fuel flowmeter QA operating quarters (as defined in § 72.2 of this chapter) after the quarter in which the required quality assurance tests are completed (note that for orifice-, nozzle-, or venturi-type fuel flowmeters, establish a new value of R_{base} or $(GHR)_{base}$ only if both a transmitter accuracy test and a primary element inspection have been performed).

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D-1g, in the electronic quarterly report required under § 75.64. Table D-3 is provided as a reference on the type of information to be recorded under § 75.59 and reported under § 75.64.

Table D-3—Baseline Information and Test Results For Fuel Flow-to-Load Test

Plant name: _____ State: _____ ORIS code: _____	
Unit/pipe ID #: _____ Fuel flowmeter system ID : _____ Calendar quarter (1st, 2nd, 3rd, 4th) and year: _____	
Range of operation: _____ to _____ MWe or klb steam/hr (indicate units)	
Reported Data Elements	
Baseline period	Quarterly analysis
Completion date and time of most recent QA sequence, i.e., primary element inspection and transmitter calibration (orifice-, nozzle-, and venturi-type flowmeters only). ____/____/____ :____	Number of hours excluded from quarterly average due to co-firing different fuels (where co-firing is not normal operation): _____ hrs.
Completion date and time of most recent flowmeter or accuracy test (all other flowmeters) ____/____/____ :____	Number of hours excluded from quarterly average due to single-fuel combustion (where co-firing is normal operation): _____ hrs.
Beginning date and time of baseline period ____/____/____ :____	Number of hours excluded from quarterly average due to ramping load: _____ hrs.
End date and time of baseline period ____/____/____ :____	Number of hours in the lower 25.0 percent of the range of operation excluded from quarterly average: _____ hrs.
Average fuel flow rate _____ (100 scfh for gas and lb/hr for oil)	Number of hours included in quarterly average: _____ hrs.
	Quarterly percentage difference between hourly ratios and baseline ratio: _____ percent.
Average load; _____ (MWe or 1000 lb steam/hr)	Test result: pass, fail.
Baseline fuel flow-to-load ratio _____ Units of fuel flow-to-load: _____	
Baseline GHR: _____ Units of fuel flow-to-load: _____	
Number of hours excluded from baseline ratio or GHR due to ramping load: _____	
Number of hours in the lower 25.0 percent of the range of operation excluded from baseline ratio or GHR: _____ hrs.	

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil. Use the sulfur content, density, and gross calorific value, determined under the provisions of this section, to calculate SO₂ mass emission rate and heat input rate for each fuel using the applicable procedures of section 3 of this appendix. The designated representative may petition for reduced GCV and or density sampling under § 75.66 if the fuel combusted has a consistent and relatively non-variable GCV or density.

TABLE D-4. -- OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations (except for missing data hours)
Oil Sulfur Content	Daily manual sampling	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 3. Maximum value allowed by contract, unless a higher sample value is obtained ¹
	As delivered (in delivery truck or barge). ¹	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 2. Maximum value allowed by contract, unless a higher sample value is obtained ¹
Oil Density	Daily manual sampling	1. Use the highest density from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 3. Maximum value allowed by contract, unless a higher sample value is obtained ¹
	As delivered (in delivery truck or barge). ¹	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 2. Maximum value allowed by contract, unless a higher sample value is obtained ¹
Oil GCV	Daily manual sampling	1. Highest fuel GCV from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 3. Maximum value allowed by contract, unless a higher sample value is obtained ¹
	As delivered (in delivery truck or barge). ¹	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; ¹ or 2. Maximum value allowed by contract, unless a higher sample value is obtained ¹

✓ Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

2.2.1 When combusting oil, use one of the following methods to sample the oil (see Table D-4): sample from the storage tank for the unit after each addition of oil to the storage tank, in accordance with section 2.2.4.2 of this appendix; or sample from the fuel lot in the shipment tank or container upon receipt of each oil delivery or from the fuel lot in the oil supplier's storage container, in accordance with section 2.2.4.3 of this appendix; or use the flow proportional sampling methodology in section 2.2.3 of this appendix; or use the daily manual sampling methodology in section 2.2.4.1 of this appendix. For purposes of this appendix, a fuel lot of oil is the mass or volume of product oil from one source (supplier or pretreatment facility), intended as one shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.). A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that no blending of any other fuel with the fuel in the storage tank occurs from the time that the fuel lot is transferred to the storage tank to the time when the fuel is combusted in the unit.

2.2.2 [Reserved]

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-95 (Reapproved 2000), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a composite sample. The sample compositing period may not exceed 7 calendar days (168 hrs). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO₂ mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

2.2.4 Manual Sampling

2.2.4.1 Daily Samples

Representative oil samples may be taken from the storage tank or fuel flow line manually every day that the unit combusts oil according to ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under § 75.6 of this part). Use either the actual daily sulfur content or the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples for the purpose of calculating SO₂ emissions under section 3 of this appendix. Use either the gross calorific value measured from that day's sample or the highest GCV from the previous 30 days' samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

2.2.4.2 Sampling From a Unit's Storage Tank

Take a manual sample after each addition of oil to the storage tank. Do not blend additional fuel with the sampled fuel prior to combustion. Sample according to the single tank composite sampling procedure or all-levels sampling procedure in ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and

Petroleum Products (incorporated by reference under § 75.6 of this part). Use the sulfur content and GCV value (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3(c) of this appendix to calculate SO₂ mass emission rate. Calculate heat input rate using the gross calorific value from either:

- (a) The most recent oil sample taken or
- (b) One of the conservative assumed values described in section 2.2.4.3(c) of this appendix. Follow the applicable provisions in section 2.2.4.3(d) of this appendix, regarding the use of assumed values.

2.2.4.3 Sampling From Each Delivery

- (a) Alternatively, an oil sample may be taken from—
 - (1) The shipment tank or container upon receipt of each lot of fuel oil or
 - (2) The supplier's storage container which holds the lot of fuel oil. (Note: a supplier need only sample the storage container once for sulfur content, GCV and, where required, the density so long as the fuel sulfur content and GCV do not change and no fuel is added to the supplier's storage container.)
- (b) For the purpose of this section, a lot is defined as a shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through a pipeline, etc.) of a single fuel.
- (c) Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference under § 75.6 of this part). Except as otherwise provided in this section, calculate SO₂ mass emission rate using the sulfur content (and where required, the density) from one of the two following conservative assumed values, and calculate heat input using the gross calorific value from one of the assumed values:
 - (1) The highest value sampled during the previous calendar year (this option is allowed for any consistent fuel which comes from a single source whether or not the fuel is supplied under a contractual agreement) or
 - (2) The maximum value indicated in the contract with the fuel supplier. Continue to use this assumed contract value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.
- (d) Continue using the assumed value(s), so long as the sample results do not exceed the assumed value(s). However, if the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then, consistent with section 2.3.7 of this appendix, begin to use the

actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO₂ mass emission rate or heat input rate. Consider the sampled value to be the new assumed sulfur content, gross calorific value, or density. Continue using this new assumed value to calculate SO₂ mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.2.5 For each oil sample that is taken on-site at the affected facility, split and label the sample and maintain a portion (at least 200 cc) of it throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. This requirement does not apply to oil samples taken from the fuel supplier's storage container, as described in section 2.2.4.3 of this appendix. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, ASTM D4294-98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry, or ASTM D5453-06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287-92 (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), ASTM D1217-93 (Reapproved 1998), Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, ASTM D1481-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, ASTM D1480-93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, ASTM D1298-99, Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, or ASTM D4052-96 (Reapproved 2002), Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for density or specific gravity by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240-00, ASTM D4809-00, ASTM D5865-01a, or D5865-10 (all incorporated by reference under § 75.6) or any other procedures listed in section 5.5 of appendix F of this part. Alternatively, the oil samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.8 Results from the oil sample analysis must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results of the analysis be available as soon as practicable, and no later than 5 business days after receipt of a request from the Administrator.

2.3 SO₂ Emissions From Combustion of Gaseous Fuels

- (a) Account for the hourly SO₂ mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.
- (b) The procedures in sections 2.3.1 and 2.3.2 of this appendix, respectively, may be used to determine SO₂ mass emissions from combustion of pipeline natural gas and natural gas, as defined in § 72.2 of this chapter. The procedures in section 2.3.3 of this appendix may be used to account for SO₂ mass emissions from any gaseous fuel combusted by a unit. For each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and GCV values used for calculations of SO₂ mass emission rates are summarized in the following Table D-5.

TABLE D-5. -- GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
Gas Total Sulfur Content	Pipeline Natural Gas with total sulfur content less than or equal to 0.5 grains/100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	1. If a contract or tariff sheet is used to qualify, use 0.0006 lb/mmBtu 2. If fuel sampling and analysis is used to qualify, use 0.0006 lb/mmBtu, provided that the results of the required annual samples do not exceed 0.5 grains/100 scf of total sulfur. If the results of an annual sample exceed 0.5 grains/100 scf, re-classify the fuel as appropriate and determine the SO₂ emission rate to be used in the calculations, using the applicable procedures in section 2.3.2 or 2.3.3 of this appendix
	Natural Gas with total sulfur content less than or equal to 20.0 grains /100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	Default SO₂ emission rate calculated from Eq. D-1h, using either: 1. The maximum total sulfur content specified in the fuel contract or tariff sheet, if a contract or tariff sheet is used to qualify; or 2. The total sulfur content, based on the most recent fuel sampling and analysis. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a "low sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample daily or, if Eq. D-1h is used to calculate a default SO₂ emission rate, sample annually.	* If daily sampling is performed, use either: 1. Actual value from the daily sample; or 2. Highest value from previous 30 samples. * If the option to use Eq. D-1h is selected, use a default SO₂ emission rate, calculated using the higher of: 1. The 90th percentile value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content ≤ 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample hourly or, if Eq. D-1h is used to calculate a default SO ₂ emission rate, sample annually.	* If hourly sampling is performed, use the actual hourly value * If the option to use Eq. D-1h is selected, use a default SO₂ emission rate, calculated using the higher of: 1. The maximum value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content > 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Sample hourly	Actual hourly sulfur content of the gas
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment.	1. Actual total sulfur content from most recent shipment; or 2. Highest total sulfur content from previous year's samples, unless a higher value is obtained in a sample¹; or 3. Maximum total sulfur content value allowed by contract, unless a higher value is obtained in a sample.¹
Gas GCV	Pipeline Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract, unless a higher value is obtained in a monthly sample;¹ or 3. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.¹
	Natural Gas * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract¹ or 3. Highest GCV from previous year's samples.¹
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment	1. Actual GCV from most recent shipment or lot; 2. Highest GCV from previous year's samples, unless a higher value is obtained in a sample;¹ or 3. Maximum GCV value allowed by contract, unless a higher value is obtained in a sample.¹

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel transmitted by pipeline and having a demonstrated "low GCV variability" using the provisions of section 2.3.5 * Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample. ¹
	Any gaseous fuel not demonstrated to have a "low GCV variability" under section 2.3.5 * Sample daily or hourly. (Note that the use of an on-line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

¹ Assumed sulfur content and GCV values (i.e., contract values or highest values from previous year) may only continue to be used if the sulfur content or GCV of each sample is no greater than the assumed value used to calculate SO₂ emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO₂ mass emissions from the combustion of a fuel that meets the definition of pipeline natural gas, in § 72.2 of this chapter, using the procedures of this section.

2.3.1.1 SO₂ Emission Rate

For a fuel that meets the definition of pipeline natural gas under § 72.2 of this chapter, the owner or operator may determine the SO₂ mass emissions using either a default SO₂ emission rate of 0.0006 lb/mmBtu and the procedures of this section, the procedures in section 2.3.2 for natural gas, or the procedures of section 2.3.3 for any gaseous fuel. For each affected unit using the default rate of 0.0006 lb/mmBtu, the owner or operator must document that the fuel combusted is actually pipeline natural gas, using the procedures in section 2.3.1.4 of this appendix.

2.3.1.2 Hourly Heat Input Rate

Calculate hourly heat input rate, in mmBtu/hr, for a unit combusting pipeline natural gas, using the procedures of section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.1 of this appendix in the calculations.

2.3.1.3 SO₂ Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO₂ mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix (when the default SO₂ emission rate is used) or Equation D-4 (if daily or hourly fuel sampling is used). Then, use the calculated SO₂ mass emission rate and the unit operating time to determine the hourly SO₂ mass emissions from pipeline natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

2.3.1.4 Documentation that a Fuel is Pipeline Natural Gas

- (a) A fuel may initially qualify as pipeline natural gas, if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 0.5 grains/100scf or less. The demonstration must be made using one of the following sources of information:
 - (1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a pipeline transportation contract; or
 - (2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in § 72.2 of this chapter, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may opt to convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if ≥98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met; or
 - (3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as pipeline natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of pipeline natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of pipeline natural gas in § 72.2 of this chapter.
- (b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of pipeline natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and

may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of pipeline natural gas.

- (c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.
- (d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as pipeline natural gas, proceed as follows:
 - (1) If the fuel still qualifies as natural gas under section 2.3.2.4 of this appendix, reclassify the fuel as natural gas and determine the appropriate default SO₂ emission rate for the fuel, according to section 2.3.2.1.1 of this appendix; or
 - (2) If the fuel does not qualify either as pipeline natural gas or natural gas, reclassify the fuel as "other gaseous fuel" and implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO₂ emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO₂ mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.
- (e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph (e), sampling "annually" means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used as follows to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the analysis of the 100 (or more) total sulfur samples since the last annual assessment shows that ≥98 percent of the samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

- (f) On-going sampling of the GCV of the pipeline natural gas is required under section 2.3.4.1 of this appendix.
- (g) For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the pipeline natural gas.

2.3.2 Natural Gas Combustion

The owner or operator may determine the SO₂ mass emissions from the combustion of a fuel that meets the definition of natural gas, in § 72.2 of this chapter, using the procedures of this section.

2.3.2.1 SO₂ Emission Rate

The owner or operator may account for SO₂ emissions either by using a default SO₂ emission rate, as determined under section 2.3.2.1.1 of this appendix, or by daily sampling of the gas sulfur content using the procedures of section 2.3.3 of this appendix. For each affected unit using a default SO₂ emission rate, the owner or operator must provide documentation that the fuel combusted is actually natural gas according to the procedures in section 2.3.2.4 of this appendix.

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, the owner or operator may either use the total sulfur content specified in a contract or tariff sheet as the SO₂ default emission rate or may calculate the default SO₂ emission rate based on fuel sampling results, using Equation D-1h. In Equation D-1h, the total sulfur content and GCV values shall be determined in accordance with Table D-5 of this appendix. Round off the calculated SO₂ default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = \left[\frac{2.0}{7000} \right] \times [10^6] \times \left[\frac{S_{\text{total}}}{GCV} \right] \quad (\text{Eq. D-1h})$$

Where:

ER = Default SO₂ emission rate for natural gas combustion, lb/mmBtu.

S_{total} = Total sulfur content of the natural gas, gr/100scf.

GCV = Gross calorific value of the natural gas, Btu/100scf.

7000 = Conversion of grains/100scf to lb/100scf.

2.0 = Ratio of lb SO₂/lb S.

10⁶ = Conversion factor (Btu/mmBtu).

2.3.2.1.2 [Reserved]

2.3.2.2 Hourly Heat Input Rate

Calculate hourly heat input rate for natural gas combustion, in mmBtu/hr, using the procedures in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.2 of this appendix in the calculations.

2.3.2.3 SO₂ Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO₂ mass emission rate, in lb/hr, using Equation D-5 in section 3.3.2 of this appendix, when the default SO₂ emission rate is used. Then, use the calculated SO₂ mass emission rate and the unit operating time to determine the hourly SO₂ mass emissions from natural gas combustion, in lb, using Equation D-12 in section 3.5.1 of this appendix.

2.3.2.4 Documentation that a Fuel Is Natural Gas

- (a) A fuel may initially qualify as natural gas, if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of 20.0 grains/100 scf or less. This demonstration must be made using one of the following sources of information:
 - (1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a transportation contract; or
 - (2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of natural gas in § 72.2 of this chapter; or
 - (3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of natural gas in § 72.2 of this chapter.

- (b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of natural gas.
- (c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.
- (d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as natural gas, the owner or operator shall re-classify the fuel as "other gaseous fuel" and shall implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D-1h in this appendix to calculate a default SO₂ emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO₂ mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.
- (e) If a fuel qualifies as natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as natural gas based on fuel sampling and analysis, the owner or operator shall sample the fuel for total sulfur content at least annually and when the fuel supply source changes. For the purposes of this paragraph, (e), sampling "annually" means that at least one sample is taken in each calendar year. The effective date of the annual total sulfur sampling requirement is January 1, 2003.
- (f) On-going sampling of the GCV of the natural gas is required under section 2.3.4.2 of this appendix.
- (g) For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the natural gas.

2.3.3 SO₂ Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO₂ mass emissions using this section for any gaseous fuel (including fuels such as refinery gas, landfill gas, digester gas, coke oven gas, blast furnace gas, coal-derived gas, producer gas or any other gas which may have a variable sulfur content).

2.3.3.1 Sulfur Content Determination

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grains/100 scf, at the frequency specified in Table D-5 of this appendix. That is: for fuel delivered in discrete shipments or lots, sample each shipment or lot. For fuel transmitted by pipeline, sample hourly unless a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel qualifies for less frequent (*i.e.*, daily or annual) sampling. If daily sampling is required, determine the sulfur content using either manual sampling or a gas chromatograph. If hourly sampling is required, determine the sulfur content using a gas chromatograph. For units that are required to monitor and report NO_x mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements of this section to document the total sulfur content of the gaseous fuel.

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072-06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, or ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, (all incorporated by reference under § 75.6 of this part). Alternatively, the gas samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.3.1.3 The sampling and analysis of daily manual samples may be performed by the owner or operator, an outside laboratory, or the gas supplier. If hourly sampling with a gas chromatograph is required, or a source chooses to use an online gas chromatograph to determine daily fuel sulfur content, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.3.1.4 Results of all sample analyses must be available no later than thirty calendar days after the sample is taken.

2.3.3.2 SO₂ Mass Emission Rate

Calculate the SO₂ mass emission rate for the gaseous fuel, in lb/hr, using Equation D-4 or D-5 (as applicable) in section 3.3.1 of this appendix. Equation D-5 may only be used if a demonstration is performed under section 2.3.6 of this appendix, showing that the fuel qualifies to use a default SO₂ emission rate to account for SO₂ mass emissions under this part. Use the appropriate sulfur content or default SO₂ emission rate in Equation D-4 or D-5, as specified in Table D-5 of this appendix. If the fuel qualifies to use Equation D-5, the default SO₂ emission rate shall be calculated using Equation D-1h in section 2.3.2.1.1 of this appendix, replacing the words "natural gas" in the equation nomenclature with the words, "gaseous fuel". In all cases, for reporting purposes, apply the results of the required periodic total sulfur samples in accordance with the provisions of section 2.3.7 of this appendix.

2.3.3.3 Hourly Heat Input Rate

Calculate the hourly heat input rate for combustion of the gaseous fuel, using the provisions in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.3 of this appendix in the calculations.

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: ASTM D1826-94 (Reapproved 1998), ASTM D3588-98, ASTM D4891-89 (Reapproved 2006), GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (all incorporated by reference under § 75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2, or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates. Alternatively, the gas samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.4.1 GCV of Pipeline Natural Gas

Determine the GCV of fuel that is pipeline natural gas, as defined in § 72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D-5: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If a unit combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter the unit operates for any amount of time. If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, apply the monthly average GCV value as described in paragraph (c) in section 2.3.7 of this appendix.

2.3.4.2 GCV of Natural Gas

Determine the GCV of fuel that is natural gas, as defined in § 72.2 of this chapter, on a monthly basis, in the same manner as described for pipeline natural gas in section 2.3.4.1 of this appendix.

2.3.4.3 GCV of Other Gaseous Fuels

For gaseous fuels other than natural gas or pipeline natural gas, determine the GCV as specified in section 2.3.4.3.1, 2.3.4.3.2 or 2.3.4.3.3, as applicable. For reporting purposes, apply the results of the required periodic GCV samples in accordance with the provisions of section 2.3.7 of this appendix.

2.3.4.3.1 For a gaseous fuel that is delivered in discrete shipments or lots, determine the GCV for each shipment or lot. The determination may be made by sampling each delivery or by sampling the supply tank after each delivery. For sampling of each delivery, use the highest GCV in the previous year's samples. For sampling from the tank after each delivery, use either the most recent GCV sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest GCV from the previous year's samples.

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas, which is not delivered in shipments or lots, and for which the owner or operator performs the 720 hour test under section 2.3.5 of this appendix, if the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly (as described in section 2.3.4.1 of this appendix). In calculations of hourly heat input for a unit, use either the most recent monthly sample, the maximum GCV specified in the fuel contract or tariff sheet, or the highest fuel GCV from the previous year's samples.

2.3.4.3.3 For any other gaseous fuel, determine the GCV at least daily and use the actual fuel GCV in calculations of unit hourly heat input. If an online gas chromatograph or on-line calorimeter is used to determine fuel GCV each day, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph or on-line calorimeter, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.5 Demonstration of Fuel GCV Variability

- (a) This optional demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The demonstration data may be used to show that monthly sampling of the GCV of the gaseous fuel or blend is sufficient, in lieu of daily GCV sampling.
- (b) To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the GCV of the gaseous fuel or blend (in Btu/100 scf). The demonstration data shall be obtained using either: hourly sampling and analysis using the methods in section 2.3.4 to determine GCV of the fuel; an on-line gas chromatograph capable of determining fuel GCV on an hourly basis; or an on-line calorimeter. For gaseous fuel produced by a variable process, the data shall be representative of and include all process operating conditions including seasonal and yearly variations in process which may affect fuel GCV.
- (c) The data shall be reduced to hourly averages. The mean GCV value and the standard deviation from the mean shall be calculated from the hourly averages. Specifically, the gaseous fuel is considered to have a low GCV variability, and monthly gas sampling for GCV may be used, if the mean value of the GCV multiplied by 1.075 is greater than the sum of the mean value and one standard deviation. If the gaseous fuel or blend does not meet this requirement, then daily fuel sampling and analysis for GCV, using manual sampling, a gas chromatograph or an on-line calorimeter is required.

2.3.6 Demonstration of Fuel Sulfur Variability

- (a) This demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The results of the demonstration may be used to show that daily sampling for sulfur in the fuel is sufficient, rather than hourly sampling. The procedures in this section may also be used to demonstrate that a particular gaseous fuel qualifies to use a default SO₂ emission rate (calculated using Equation D-1h in section 2.3.2.1.1 of this appendix) for the purpose of reporting hourly SO₂ mass emissions under this part. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gaseous fuel (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph (GC) capable of determining fuel total sulfur content on an hourly basis. For gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.
- (b) If the data are collected with an on-line GC, reduce the data to hourly average values of the total sulfur content of the fuel. If manual hourly sampling is used, the results of each hourly sample analysis shall be the total sulfur value for that hour. Express all hourly average values of total sulfur content in units of grains/100 scf. Use all of the hourly average values of total sulfur content in grains/100 scf to calculate the mean value and the standard deviation. Also determine the 90th percentile and maximum hourly values of the total sulfur content for the data set. If the standard deviation of the hourly values from the mean does not exceed 5.0 grains/100 scf, the fuel has a low sulfur variability. If the standard deviation exceeds 5.0 grains/100 scf, the fuel has a high sulfur variability. Based on the results of this determination, establish the required sampling frequency and SO₂ mass emissions methodology for the gaseous fuel, as follows:
 - (1) If the gaseous fuel has a low sulfur variability (irrespective of the total sulfur content), the owner or operator may either perform daily sampling of the fuel's total sulfur content using manual sampling or a GC, or may report hourly SO₂ mass emissions data using a default SO₂ emission rate calculated by substituting the 90th percentile value of the total sulfur content in Equation D-1h.
 - (2) If the gaseous fuel has a high sulfur variability, but the maximum hourly value of the total sulfur content does not exceed 20 grains/100 scf, the owner or operator may either perform hourly sampling of the fuel's total sulfur content using an on-line GC, or may report hourly SO₂ mass emissions data using a default SO₂ emission rate calculated by substituting the maximum value of the total sulfur content in Equation D-1h.
 - (3) If the gaseous fuel has a high sulfur variability and the maximum hourly value of the total sulfur content exceeds 20 grains/100 scf, the owner or operator shall perform hourly sampling of the fuel's total sulfur content, using an on-line GC.

- (4) Any gaseous fuel under paragraph (b)(1) or (b)(2) of this section, for which the owner or operator elects to use a default SO₂ emission rate for reporting purposes is subject to the annual total sulfur sampling requirement under section 2.3.2.4(e) of this appendix.

2.3.7 Application of Fuel Sampling Results

For reporting purposes, apply the results of the required periodic fuel samples described in Tables D-4 and D-5 of this appendix as follows. Use Equation D-1h to recalculate the SO₂ emission rate, as necessary.

- (a) For daily samples of total sulfur content or GCV:
 - (1) If the actual value is to be used in the calculations, apply the results of each daily sample to all hours in the day on which the sample is taken; or
 - (2) If the highest value in the previous 30 daily samples is to be used in the calculations, apply that value to all hours in the current day. If, for a particular unit, fewer than 30 daily samples have been collected, use the highest value from all available samples until 30 days of historical sampling results have been obtained.
- (b) For annual samples of total sulfur content:
 - (1) For pipeline natural gas, use the results of annual sample analyses in the calculations only if the results exceed 0.5 grains/100 scf. In that case, if the fuel still qualifies as natural gas, follow the procedures in paragraph (b)(2) of this section. If the fuel does not qualify as natural gas, the owner or operator shall implement the procedures in section 2.3.3 of this appendix, in the time frame specified in sections 2.3.1.4(d) and 2.3.2.4(d) of this appendix;
 - (2) For natural gas, if only one sample is taken, apply the results beginning at the date on which the sample was taken. If multiple samples are taken and averaged, apply the results beginning at the date on which the last sample used in the annual assessment was taken;
 - (3) For other gaseous fuels with an annual sampling requirement under section 2.3.6(b)(4) of this appendix, use the sample results in the calculations only if the results exceed the 90th percentile value or maximum value (as applicable) from the 720-hour demonstration of fuel sulfur content and variability under section 2.3.6 of this appendix.
- (c) For monthly samples of the fuel GCV:
 - (1) If the actual monthly value is to be used in the calculations and only one sample is taken, apply the results starting from the date on which the sample was taken. If multiple samples are taken and averaged, apply the monthly average GCV value to the entire month; or
 - (2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV

sample (or, if multiple samples are taken and averaged, if the monthly average exceeds the assumed value). In that case, if only one monthly sample is taken, use the sampled value, starting from the date on which the sample was taken. If multiple samples are taken and averaged, use the average value for the entire month in which the assumed value was exceeded. Consider the sample (or, if applicable, monthly average) results to be the new assumed value. Continue using the new assumed value unless and until one of the following occurs (as applicable to the reporting option selected): The assumed value is superseded by a higher value from a subsequent monthly sample (or by a higher monthly average); or the assumed value is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or both the calendar year in which the new sampled value (or monthly average) exceeded the assumed value and the subsequent calendar year have elapsed.

- (d) For samples of gaseous fuel delivered in shipments or lots:
 - (1) If the actual value for the most recent shipment is to be used in the calculations, apply the results of the most recent sample, from the date on which the sample was taken until the date on which the next sample is taken; or
 - (2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value unless a higher value is obtained in a sample of a shipment. In that case, use the sampled value, starting from the date on which the sample was taken. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until: it is superseded by a higher value from a sample of a subsequent shipment; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.
- (e) When the owner or operator elects to use assumed values in the calculations, the results of periodic samples of sulfur content and GCV which show that the assumed value has not been exceeded need not be reported. Keep these sample results on file, in a format suitable for inspection.
- (f) Notwithstanding the requirements of paragraphs (b) through (d) of this section, in cases where the sample results are provided to the owner or operator by the supplier of the fuel, the owner or operator shall begin using the sampling results on the date of receipt of those results, rather than on the date that the sample was taken.

2.4 Missing Data Procedures.

When data from the procedures of this part are not available, provide substitute data using the following procedures.

2.4.1 Missing Data for Oil and Gas Samples

When fuel sulfur content, gross calorific value or, when necessary, density data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.5, 2.2.6, 2.2.7, 2.3.3.1.2, or 2.3.4 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D-6 of this appendix. Except for the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, the missing data values in Table D-6 shall be reported whenever the results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year, irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year). For the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, if a valid annual sample has not been obtained by the end of a particular calendar year, the appropriate missing data value in Table D-6 shall be reported, beginning with the first unit operating hour in the next calendar year. The substitute data value(s) shall be used until the next valid sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the "highest value from the previous year" when that reporting option is used; missing data values shall not be used in the determination.

TABLE D-6. -- MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Total Sulfur Content	- For pipeline natural gas, where annual sampling is required, substitute 0.002 lb/mmBtu for each hour of the missing data period. - For natural gas (or other gaseous fuel that qualifies to use a default SO₂ emission rate under section 2.3.6 of this appendix), where annual sampling is required, substitute 1.5 times the default SO₂ emission rate in use at the time of the missing data period. - For any gaseous fuel sampled daily, 1.5 times the highest total sulfur content value from the previous 30 days on which valid samples were obtained. - For any gaseous fuel sampled hourly, the highest total sulfur content value from the previous 720 hourly samples.
Gas GCV/Heat Content	110,000 Btu/100 scf for pipeline natural gas, natural gas or landfill gas. 150,000 Btu/100 scf for butane or refinery gas. 210,000 Btu/100 scf for propane or any other gaseous fuel.

2.4.2 Missing Data Procedures for Fuel Flow Rate

Whenever data are missing from any primary fuel flowmeter system (as defined in § 72.2 of this chapter) and there is no backup system available to record the fuel flow rate, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. Alternatively, for a fuel flowmeter system used to measure the fuel combusted by a peaking unit, the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix may be used. Before using the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix, establish load ranges for the unit using the procedures of section 2 in appendix C to this part, except for units that do not produce electrical output (i.e., megawatts) or thermal output (e.g., klb of steam per hour). The owner or operator of a unit that does not produce electrical or thermal output shall either perform missing data substitution without segregating the fuel flow rate data into bins, or may petition the Administrator under § 75.66 for permission to segregate the data into operational bins. When load ranges are used for fuel flow rate missing data purposes, separate, fuel-specific databases shall be created and maintained. A database shall be kept for each type of fuel combusted in the unit, for the hours in which the fuel is combusted alone in the unit. An additional database shall be kept for each type of fuel, for the hours in which it is co-fired with any other type(s) of fuel(s).

2.4.2.1 Simplified Fuel Flow Rate Missing Data Procedure for Peaking Units

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following:

- (a) The maximum fuel flow rate the unit is capable of combusting or
- (b) The maximum flow rate that the fuel flowmeter can measure (i.e., the upper range value of the flowmeter).

2.4.2.2 Standard Missing Data Procedures—Single Fuel Hours

For missing data periods that occur when only one type of fuel is being combusted, provide substitute data for each hour in the missing data period as follows.

2.4.2.2.1 If load-based missing data procedures are used, substitute the arithmetic average of the hourly fuel flow rate(s) measured and recorded by a certified fuel flowmeter system at the corresponding operating unit load range during the previous 720 operating hours in which the unit combusted only that same fuel. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range, if such data are available. If no quality-assured fuel flow rate data are available at either the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.2.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute data for each hour of the missing data period as follows. Substitute the arithmetic average of the hourly fuel flow rates measured and recorded by a certified fuel flowmeter system during

the previous 720 operating hours in which the unit combusted only that same fuel. If no quality-assured fuel flow rate data are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3 Standard Missing Data Procedures—Multiple Fuel Hours

For missing data periods that occur when two or more different types of fuel are being co-fired, provide substitute fuel flow rate data for each hour of the missing data period as follows.

2.4.2.3.1 If load-based missing data procedures are used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system at the corresponding load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no such quality-assured fuel flow rate data are available at the corresponding load range, use data from the next higher load range (if available). If no quality-assured fuel flow rate data are available for co-fired hours, either at the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute fuel flow rate data for each hour of the missing data period as follows. Substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no quality-assured fuel flow rate data for co-fired hours are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.3 If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in section 2.4.2.3.1 or 2.4.2.3.2 of this appendix (as applicable) separately for each type of fuel.

2.4.2.3.4 If the missing data substitution required in section 2.4.2.3.1 or 2.4.2.3.2 causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input. Manual entry of the adjusted substitute data values is permitted.

2.4.3. In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, use three years (26,280 clock hours) in place of the prescribed lookback period. In addition, for a new or newly-affected unit, until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in sections 2.4.2.2 and 2.4.2.3 of this appendix, use all of the available fuel flowmeter data to determine the appropriate substitute data values.

3. Calculations

Calculate hourly SO₂ mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO₂ mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO₂ mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO₂ mass emissions for a particular fuel for the

unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO₂ mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil.

3.1 SO₂ Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D-2 to calculate SO₂ mass emission rate per hour (lb/hr):

$$SO_{2\text{rate-oil}} = 2.0 \times OIL_{\text{rate}} \times \frac{\%S_{\text{oil}}}{100.0} \quad (\text{Eq. D-2})$$

Where:

SO_{2rate-oil} = Hourly mass emission rate of SO₂ emitted from combustion of oil, lb/hr.

OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.

%S_{oil} = Percentage of sulfur by weight in the oil.

2.0 = Ratio of lb SO₂/lb S.

3.1.2 Record the SO₂ mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil flow rate measurements and the density or specific gravity of the oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables (incorporated by reference under (§ 75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.6 of this appendix, use Equation D-3 to calculate the rate of the mass of oil consumed (in lb/hr):

$$OIL_{\text{rate}} = V_{\text{oil-rate}} \times D_{\text{oil}} \quad (\text{Eq. D-3})$$

Where:

OIL_{rate} = Mass rate of oil consumed per hr, lb/hr.

V_{oil-rate} = Volume rate of oil consumed per hr, measured in scf/hr, gal/hr, barrels/hr, or m³/hr.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m³.

3.3 SO₂ Mass Emission Rate Calculation for Gaseous Fuels

- 3.3.1 Use Equation D-4 to calculate the SO₂ mass emission rate when using the optional gas sampling and analysis procedures in sections 2.3.1 and 2.3.2 of this appendix, or the required gas sampling and analysis procedures in section 2.3.3 of this appendix. Total sulfur content of a fuel must be determined using the procedures of 2.3.3.1.2 of this appendix:

$$SO_{2\text{rate-gas}} = \left(\frac{2.0}{7000} \right) \times GAS_{\text{rate}} \times S_{\text{gas}} \quad (\text{Eq. D-4})$$

Where:

SO₂rate-gas = Hourly mass rate of SO₂ emitted due to combustion of gaseous fuel, lb/hr.

GASrate = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

Sgas = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO₂/lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

- 3.3.2 Use Equation D-5 to calculate the SO₂ mass emission rate when using a default emission rate from section 2.3.1.1 or 2.3.2.1.1 of this appendix:

$$SO_{2\text{rate}} = ER \times HI_{\text{rate}} \quad (\text{Eq. D-5})$$

where:

SO₂rate = Hourly mass emission rate of SO₂ from combustion of a gaseous fuel, lb/hr.

ER = SO₂ emission rate from section 2.3.1.1 or 2.3.2.1.1, of this appendix, lb/mmBtu.

HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

- 3.3.3 Record the SO₂ mass emission rate for each hour when the unit combusts a gaseous fuel.

3.4 Calculation of Heat Input Rate

3.4.1 Heat Input Rate for Gaseous Fuels

- (a) Determine total hourly gas flow or average hourly gas flow rate with a fuel flowmeter in accordance with the requirements of section 2.1 of this appendix and the fuel GCV in accordance with the requirements of section 2.3.4 of this appendix. If necessary perform the 720-hour test under section 2.3.5 to determine the appropriate fuel GCV sampling frequency.

- (b) Then, use Equation D-6 to calculate heat input rate from gaseous fuels for each hour.

$$HI_{\text{rate-gas}} = \frac{GAS_{\text{rate}} \times GCV_{\text{gas}}}{10^6} \quad (\text{Eq. D-6})$$

Where:

$HI_{\text{rate-gas}}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

GCV_{gas} = Gross calorific value of gaseous fuel, Btu/100 scf.

10^6 = Conversion of Btu to mmBtu.

- (c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D-6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D-7:

$$GAS_{\text{rate}} = \frac{GAS_{\text{unit}}}{t} \quad (\text{Eq. D-7})$$

Where:

GAS_{rate} = Average volumetric flow rate of fuel for the portion of the hour in which the unit operated, 100 scf/hr.

GAS_{unit} = Total fuel combusted during the hour, 100 scf.

t = Unit operating time, hour or 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).

3.4.2 Heat Input Rate From the Combustion of Oil

- (a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.

Then, use Equation D-8 to calculate hourly heat input rate from oil for each hour:

$$HI_{\text{rate-oil}} = OIL_{\text{rate}} \frac{GCV_{\text{oil}}}{10^6} \quad (\text{Eq. D-8})$$

Where:

$HI_{\text{rate-oil}}$ = Hourly heat input rate from combustion of oil, mmBtu/hr.

OIL_{rate} = Mass rate of oil consumed per hour, as determined using procedures in section 3.2.3 of this appendix, in lb/hr, tons/hr, or kg/hr.

GCV_{oil} = Gross calorific value of oil, Btu/lb, Btu/ton, or Btu/kg.

10^6 = Conversion of Btu to mmBtu.

- (b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D-8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D-9:

$$OIL_{rate} = \frac{OIL_{unit}}{t} \quad (\text{Eq. D-9})$$

Where:

OIL_{rate} = Average fuel flow rate for the portion of the hour which the unit operated in lb/hr.

OIL_{unit} = Total fuel combusted during the hour, lb.

t = Unit operating time, hour or 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).

- (c) For affected units that are not subject to an Acid Rain emissions limitation, but are regulated under a State or federal NO_x mass emissions reduction program that adopts the requirements of subpart H of this part, the following alternative method may be used to determine the heat input rate from oil combustion, when the oil flowmeter measures the flow rate of oil volumetrically. In lieu of measuring the oil density and converting the volumetric oil flow rate to a mass flow rate, Equation D-8 may be applied on a volumetric basis. If this option is selected, express the terms OIL_{rate} and GCV_{oil} in Equation D-8 in units of volume rather than mass. For example, the units of OIL_{rate} may be gal/hr and the units of GCV_{oil} may be Btu/gal.

3.4.3 Apportioning Heat Input Rate to Multiple Units

- (a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.
- (b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW_e or 1000 lb of steam/hr (klb/hr) using Equation F-21a or F-21b in appendix F to this part, as applicable:

Equation D-10 [Reserved]

Equation D-11 [Reserved]

- (c) Use the total apportioned fuel flow calculated from Equation F-21a or F-21b to calculate the hourly unit heat input rate, using Equations D-6 and D-7 (for gas) or Equations D-8 and D-9 (for oil).

3.5 Conversion of Hourly Rates to Hourly, Quarterly, and Year-to-Date Totals

3.5.1 Hourly SO₂ Mass Emissions from the Combustion of all Fuels. Determine the total mass emissions for each hour from the combustion of all fuels using Equation D-12 (On and after January 1, 2009, determine the total mass emission rate (in lbs/hr) for each hour from the combustion of all fuels by dividing Equation D-12 by the actual unit operating time for the hour):

$$M_{SO_2-hr} = \sum_{\text{all-fuels}} SO_{2\text{ rate-}i} t_i \quad (\text{Eq. D-12})$$

Where:

M_{SO_2-hr} = Total mass of SO₂ emissions from all fuels combusted during the hour, lb.

$SO_{2\text{ rate-}i}$ = SO₂ mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.2 Quarterly Total SO₂ Mass Emissions

Sum the hourly SO₂ mass emissions in lb as determined from Equation D-12 for all hours in a quarter using Equation D-13:

$$M_{SO_2-qtr} = \frac{1}{2000} \sum_{\text{all-hours-in-qtr}} M_{SO_2-hr} \quad (\text{Eq. D-13})$$

Where:

M_{SO_2-qtr} = Total mass of SO₂ emissions from all fuels combusted during the quarter, tons.

M_{SO_2-hr} = Hourly SO₂ mass emissions determined using Equation D-12, lb.

2000= Conversion factor from lb to tons.

3.5.3 Year to Date SO₂ Mass Emissions

Calculate and record SO₂ mass emissions in the year to date using Equation D-14:

$$M_{SO_2-YTD} = \sum_{q=1}^{\text{current-quarter}} M_{SO_2-qtr} \quad (\text{Eq. D-14})$$

Where:

M_{SO_2-YTD} = Total SO_2 mass emissions for the year to date, tons.

M_{SO_2-qtr} = Total SO_2 mass emissions for the quarter, tons.

3.5.4 Hourly Total Heat Input Rate and Heat Input from the Combustion of all Fuels

3.5.4.1 Determine the total heat input in mmBtu for each hour from the combustion of all fuels using Equation D-15:

$$HI_{hr} = \sum_{\text{all-fuels}} HI_{rate-i} t_i \quad (\text{Eq. D-15})$$

Where:

HI_{hr} = Total heat input from all fuels combusted during the hour, mmBtu.

HI_{rate-i} = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.4.2 For reporting purposes, determine the heat input rate to each unit, in mmBtu/hr, for each hour from the combustion of all fuels using Equation D-15a:

$$HI_{rate-hr} = \frac{\sum_{\text{all-fuels}} HI_{rate-i} t_i}{t_u} \quad (\text{Eq. D-15a})$$

Where:

$HI_{rate-hr}$ = Total heat input rate from all fuels combusted during the hour, mmBtu/hr.

HI_{rate-i} = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

t_u = Unit operating time

3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D-15 for all hours in a quarter using Equation D-16:

$$HI_{qtr} = \sum_{all\ hours\ in\ qtr} HI_h \quad (Eq. D-16)$$

Where:

HI_{qtr} = Total heat input from all fuels combusted during the quarter, mmBtu.

HI_h = Hourly heat input determined using Equation D-15, mmBtu.

3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D-17.

$$HI_{YTD} = \sum_{q=1}^{current-quarter} HI_{qtr} \quad (Eq. D-17)$$

HI_{YTD} = Total heat input for the year to date, mmBtu.

HI_{qtr} = Total heat input for the quarter, mmBtu.

3.6 Records and Reports

Calculate and record quarterly and cumulative SO₂ mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. Calculate and record SO₂ emissions and heat input data using a data acquisition and handling system. Report these data in a standard electronic format specified by the Administrator.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26548, 26551, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28652, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40460, 40472, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4369, Jan. 24, 2008; 76 FR 17324, Mar. 28, 2011; 76 FR 20536, Apr. 13, 2011; 77 FR 2460, Jan. 18, 2012]

Editorial Note: At 67 FR 53505, Aug. 16, 2002, section 2.4.1 Table D-6 was amended. However, this table is a photographed graphic and the amendments could not be incorporated.

Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

1. Applicability

1.1 Unit Operation Requirements

This NO_x emissions estimation procedure may be used in lieu of a continuous NO_x emission monitoring system (lb/mmBtu) for determining the average NO_x emission rate and hourly NO_x rate from gas-fired peaking units and oil-fired peaking units as defined in § 72.2 of this chapter. If a unit's operations exceed the levels required to be a peaking unit, the owner or operator shall install and certify a NO_x-diluent continuous emission monitoring system no later than December 31 of the following calendar year. If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_x emission rate (MER) (as defined in § 72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified. The provision of § 75.12 apply to excepted monitoring systems under this appendix.

1.2 Certification

1.2.1 Pursuant to the procedures in § 75.20, complete all testing requirements to certify use of this protocol in lieu of a NO_x continuous emission monitoring system no later than the applicable deadline specified in § 75.4. Apply to the Administrator for certification to use this method no later than 45 days after the completion of all certification testing. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.2.2 [Reserved]

2. Procedure

2.1 Initial Performance Testing

Use the following procedures for: measuring NO_x emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_x emission rate, in order to determine the emission rate of the unit(s). The requirements in section 6.1.2 of appendix A to this part shall apply to any stack testing performed to obtain O₂ and NO_x concentration measurements under this appendix, either for units using the excepted methodology in this appendix or for units using the low mass emissions excepted methodology in § 75.19.

2.1.1 Load Selection

Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Select the maximum and minimum operating load from the operating history of the unit during the most recent two years. (If projections indicate that the unit's maximum or minimum operating load during the next five years will be significantly different from the most recent two years, select the maximum and minimum operating load based on the projected dispatched load of the unit.) For new gas-fired peaking units or new oil-fired peaking units, select the maximum and minimum operating load from the expected maximum and minimum load to be dispatched to the unit in the first five calendar years of operation.

2.1.2 NO_x and O₂ Concentration Measurements

Use the following procedures to measure NO_x and O₂ concentration in order to determine NO_x emission rate.

- 2.1.2.1 For boilers, select an excess O₂ level for each fuel (and, optionally, for each combination of fuels) to be combusted that is representative for each of the four or more load levels. If a boiler operates using a single, consistent combination of fuels only, the testing may be performed using the combination rather than each fuel. If a fuel is combusted only for the purpose of testing ignition of the burners for a period of five minutes or less per ignition test or for start-up, then the boiler NO_x emission rate does not need to be tested separately for that fuel. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_x and O₂ at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO_x and O₂ concentrations according to method 7E and 3A in appendix A of part 60 of this chapter. Use a minimum of 12 sample points, located according to Method 1 in appendix A-1 to part 60 of this chapter. The designated representative for the unit may also petition the Administrator under § 75.66 to use fewer sampling points. Such a petition shall include the proposed alternative sampling procedure and information demonstrating that there is no concentration stratification at the sampling location.
- 2.1.2.2 For stationary gas turbines, sample at a minimum of 12 points per run at each load level. Locate the sample points according to Method 1 in appendix A-1 to part 60 of this chapter. For each fuel or consistent combination of fuels (and, optionally, for each combination of fuels), measure the NO_x and O₂ concentrations at each sampling point using methods 7E and 3A in appendices A-4 and A-2 to part 60 of this chapter. For diesel or dual fuel reciprocating engines, select the sampling site to be as close as practicable to the exhaust of the engine.
- 2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_x and O₂ readings to stabilize) prior to commencing NO_x, O₂, and heat input measurements. Determine the measurement system response time according to sections 8.2.5 and 8.2.6 of method 7E in appendix A-4 to part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the measurement system response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

2.1.3 Heat Input

Measure the total heat input (mmBtu) and heat input rate during testing (mmBtu/hr) as follows:

- 2.1.3.1 When the unit is combusting fuel, measure and record the flow of fuel consumed. Measure the flow of fuel with an in-line flowmeter(s) and automatically record the data. If a portion of the flow is diverted from the unit without being burned, and that diversion

occurs downstream of the fuel flowmeter, an in-line flowmeter is required to account for the unburned fuel. Install and calibrate in-line flow meters using the procedures and specifications contained in sections 2.1.2, 2.1.3, 2.1.4, and 2.1.5 of appendix D of this part. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions of 68 °F and 29.92 inches of mercury.

2.1.3.2 For liquid fuels, analyze fuel samples taken according to the requirements of section 2.2 of appendix D of this part to determine the heat content of the fuel. Determine heat content of liquid or gaseous fuel in accordance with the procedures in appendix F of this part. Calculate the heat input rate during testing (mmBtu/hr) associated with each load condition in accordance with equations F-19 or F-20 in appendix F of this part and total heat input using equation E-1 of this appendix. Record the heat input rate at each heat input/load point.

2.1.4 Emergency Fuel

The designated representative of a unit that is restricted by its federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available may claim an exemption from the requirements of this appendix for testing the NO_x emission rate during combustion of the emergency fuel. To claim this exemption, the designated representative shall include in the monitoring plan for the unit documentation that the permit restricts use of the fuel to emergencies only. When emergency fuel is combusted, report the maximum potential NO_x emission rate for the emergency fuel, in accordance with section 2.5.2.3 of this appendix. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

2.1.5 Tabulation of Results

Tabulate the results of each baseline correlation test for each fuel or, as applicable, combination of fuels, listing: time of test, duration, operating loads, heat input rate (mmBtu/hr), F-factors, excess oxygen levels, and NO_x concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.001 lb/mmBtu) according to equation F-5 of appendix F of this part or 19-3 in method 19 of appendix A of part 60 of this chapter, as appropriate. Calculate the NO_x emission rate in lb/mmBtu for each sampling point and determine the arithmetic average NO_x emission rate of each test run. Calculate the arithmetic average of the boiler excess oxygen readings for each test run. Record the arithmetic average of the three test runs as the NO_x emission rate and the boiler excess oxygen level for the heat input/load condition.

2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel and (as applicable) combination of fuels combusted according to the following procedures.

2.1.6.1 Plot the heat input rate (mmBtu/hr) as the independent (or x) variable and the NO_x emission rates (lb/mmBtu) as the dependent (or y) variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

2.1.6.2 Units that co-fire gas and oil may be tested while firing gas only and oil only instead of testing with each combination of fuels. In this case, construct a graph for each fuel.

2.2 Periodic NO_x Emission Rate Testing

Retest the NO_x emission rate of the gas-fired peaking unit or the oil-fired peaking unit while combusting each type of fuel (or fuel mixture) for which a NO_x emission rate versus heat input rate correlation curve was derived, at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in section 2.5 of this appendix, beginning with the first unit operating hour after the end of the 20th calendar quarter. Continue using the missing data procedures until the required retest has been passed. Note that missing data substitution is fuel-specific (i.e., the use of substitute data is required only when combusting a fuel (or fuel mixture) for which the retesting deadline has not been met). Each time that a new fuel-specific correlation curve is derived from retesting, the new curve shall be used to report NO_x emission rate, beginning with the first operating hour in which the fuel is combusted, following the completion of the retest. Notwithstanding this requirement, for non-Acid Rain Program units that report NO_x mass emissions and heat input data only during the ozone season under § 75.74(c), if the NO_x emission rate testing is performed outside the ozone season, the new correlation curve may be used beginning with the first unit operating hour in the ozone season immediately following the testing.

2.3 Other Quality Assurance/Quality Control-Related NO_x Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, or where the Administrator issues a notice requesting retesting because the NO_x emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Administrator, complete retesting of the NO_x emission rate by the earlier of: (1) 30 unit operating days (as defined in § 72.2 of this chapter) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Administrator to re-verify the unit's NO_x emission rate. Submit test results in accordance with § 75.60 within 45 days of completing the retesting.

2.3.1 For a stationary gas turbine, select at least four operating parameters indicative of the turbine's NO_x formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. If the gas turbine uses water or steam injection for NO_x control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NO_x-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_x emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

- 2.3.2 For a diesel or dual-fuel reciprocating engine, select at least four operating parameters indicative of the engine's NO_x formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the engine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. Any operating parameter critical for NO_x control shall be included. During the NO_x heat-input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Redetermine the NO_x emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.
- 2.3.3 For boilers using the procedures in this appendix, the NO_x emission rate heat input correlation for each fuel and (optional) combination of fuels shall be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than 2 percentage points O₂ from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO_x emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

2.4 Procedures for Determining Hourly NO_x Emission Rate

- 2.4.1 Record the time (hr. and min.), load (MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output), fuel flow rate and heat input rate (using the procedures in section 2.1.3 of this appendix) for each hour during which the unit combusts fuel. Calculate the total hourly heat input using equation E-1 of this appendix. Record the heat input rate for each fuel to the nearest 0.1 mmBtu/hr. During partial unit operating hours or during hours where more than one fuel is combusted, heat input must be represented as an hourly rate in mmBtu/hr, as if the fuel were combusted for the entire hour at that rate (and not as the actual, total heat input during that partial hour or hour) in order to ensure proper correlation with the NO_x emission rate graph.
- 2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_x emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.001 lb/mmBtu NO_x. For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.
- 2.4.3 To determine the NO_x emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO_x emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO_x emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO_x emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E-1. Calculate a Btu-weighted

average of the emission rates for all fuels using Equation E-2 of this appendix. For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

- 2.4.4 For each hour, record the critical quality assurance parameters, as identified in the monitoring plan, and as required by section 2.3 of this appendix from the date and hour of the completion of the most recent test for each type of fuel.

2.5 Missing Data Procedures

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_x emission rate data has not been obtained according to the procedures and specifications of this appendix. For the purpose of providing substitute data, calculate the maximum potential NO_x emission rate (as defined in § 72.2 of this chapter) for each type of fuel combusted in the unit.

- 2.5.1 Use the procedures of this section whenever any of the quality assurance/quality control parameters exceeds the limits in section 2.3 of this appendix or whenever any of the quality assurance/quality control parameters are not available.
- 2.5.2 Substitute missing NO_x emission rate data using the highest NO_x emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels, except as provided in sections 2.5.2.1, 2.5.2.2, 2.5.2.3, and 2.5.2.4 of this appendix.
- 2.5.2.1 If the measured heat input rate during any unit operating hour is higher than the highest heat input rate from the baseline correlation tests, the NO_x emission rate for the hour is considered to be missing. Provide substitute data for each such hour, according to section 2.5.2.1.1 or 2.5.2.1.2 of this appendix, as applicable. Either:
- 2.5.2.1.1 Substitute the higher of: the NO_x emission rate obtained by linear extrapolation of the correlation curve, or the maximum potential NO_x emission rate (MER) (as defined in § 72.2 of this chapter), specific to the type of fuel being combusted. (For fuel mixtures, substitute the highest NO_x MER value for any fuel in the mixture.) For units with NO_x emission controls, the extrapolated NO_x emission rate may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix); or
- 2.5.2.1.2 Substitute 1.25 times the highest NO_x emission rate from the baseline correlation tests for the fuel (or fuel mixture) being combusted in the unit, not to exceed the MER for that fuel (or mixture). For units with NO_x emission controls, the option to report 1.25 times the highest emission rate from the correlation curve may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix).
- 2.5.2.2 For a unit with add-on NO_x emission controls (e.g., steam or water injection, selective catalytic reduction), if, for any unit operating hour, the emission controls are either not in operation or if appropriate parametric data are unavailable to ensure proper operation of the controls, the NO_x emission rate for the hour is considered to be missing. Substitute the fuel-specific MER (as defined in § 72.2 of this chapter) for each such hour.

- 2.5.2.3 When emergency fuel (as defined in § 72.2) is combusted in the unit, report the fuel-specific NO_x MER for each hour that the fuel is combusted, unless a NO_x correlation curve has been derived for the fuel.
- 2.5.2.4 Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done for that type of fuel (or fuel mixture), substitute the fuel-specific NO_x MER (as defined in § 72.2 of this chapter) for each hour in which that fuel (or mixture) is combusted until a new baseline correlation test for that fuel (or mixture) has been successfully completed. For fuel mixtures, report the highest of the individual MER values for the components of the mixture.
- 2.5.3 Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_x emission rate data according to the procedures and specifications of this appendix.
- 2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.
- 2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = HI_{fuel1}t_1 + HI_{fuel2}t_2 + HI_{fuel3}t_3 + \dots + HI_{lastfuel}t_{last} \quad (\text{Eq. E-1})$$

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel1,2,3,\dots,last}$ = Heat input rate from each fuel, in mmBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3,\dots,last}$ = Fuel usage time for each fuel (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)).

3.2 F-factors

Determine the F-factors for each fuel or combination of fuels to be combusted according to section 3.3 of appendix F of this part.

3.3 NO_x Emission Rate

3.3.1 Conversion from Concentration to Emission Rate

Convert the NO_x concentrations (ppm) and O₂ concentrations to NO_x emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to April 1, 2000, or to the nearest 0.001 lb/mmBtu for tests performed on and after April 1, 2000), according to the appropriate one of the following equations: F-5 in appendix F to this part for dry basis concentration measurements or 19-3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

3.3.2 Quarterly Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO_x emission rate according to equation F-9 in appendix F of this part.

3.3.3 Annual Average NO_x Emission Rate

Report the average emission rate (lb/mmBtu) for the calendar year as required in subpart G of this part. Calculate the average NO_x emission rate according to equation F-10 in appendix F of this part.

3.3.4 Average NO_x Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} (E_f \times HI_f t_f)}{H_T} \quad (\text{Eq. E-2})$$

Where:

E_h = NO_x emission rate for the unit for the hour, lb/mmBtu.

E_f = NO_x emission rate for the unit for a given fuel at heat input rate HI_f , lb/mmBtu.

HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

H_T = Total heat input for all fuels for the hour from Equation E-1.

t_f = Fuel usage time for each fuel (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)).

Note: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F-19 or F-20.

4. Quality Assurance/Quality Control Plan

Include a section on the NO_x emission rate determination as part of the monitoring quality assurance/quality control plan required under § 75.21 and appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to, the following: (1) a copy of all data and results from the initial NO_x emission rate testing, including the values of quality assurance parameters specified in section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO_x emission rate load correlation testing; (3) a copy of the recommended range of quality assurance- and quality control-related operating parameters.

- 4.1 Submit a copy of the recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_x emission rate test that determined the unit's NO_x emission rate, along with the unit's revised monitoring plan submitted with the certification application.
- 4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the recommended operating range.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26551, May 17, 1995; 64 FR 28665, May 26, 1999; 67 FR 40473, 40474, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 73 FR 4372, Jan. 24, 2008; 76 FR 17325, Mar. 28, 2011]

Appendix F to Part 75—Conversion Procedures

1. Applicability

Use the procedures in this appendix to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. Procedures for SO₂ Emissions

Use the following procedures to compute hourly SO₂ mass emission rate (in lb/hr) and quarterly and annual SO₂ total mass emissions (in tons).

- 2.1 When measurements of SO₂ concentration and flow rate are on a wet basis, use the following equation to compute hourly SO₂ mass emission rate (in lb/hr):

$$E_h = KC_h Q_h \quad (\text{Eq. F-1})$$

Where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO₂, (lb/scf)/ppm.

C_h = Hourly average SO₂ concentration during unit operation, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

- 2.2 When measurements by the SO₂ pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO₂ mass emission rate (in lb/hr):

$$E_h = K C_{hp} Q_{hs} \frac{(100 - \%H_2O)}{100} \quad (\text{Eq. F-2})$$

where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO₂, (lb/scf)/ppm.

C_{hp} = Hourly average SO₂ concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

- 2.3 Use the following equations to calculate total SO₂ mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

$$E_q = \frac{\sum_{h=1}^n E_h t_h}{2000}$$

(Eq. F-3)

Where:

E_q = Quarterly total SO₂ mass emissions, tons.

E_h = Hourly SO₂ mass emission rate, lb/hr.

t_h = Unit operating time, hour or 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).

n = Number of hourly SO₂ emissions values during calendar quarter.

2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^4 E_q \quad (\text{Eq. F-4})$$

Where:

E_a = Annual total SO₂ mass emissions, tons.

E_q = Quarterly SO₂ mass emissions, tons.

q = Quarters for which E_q are available during calendar year.

- 2.4 Round all SO₂ mass emission rates and totals to the nearest tenth.

3. Procedures for NO_x Emission Rate

Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Perform measurements of NO_x and diluent (O₂ or CO₂) concentrations on the same moisture (wet or dry) basis.

- 3.1 When the NO_x continuous emission monitoring system uses O₂ as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K C_h F \frac{20.9}{20.9 - \%O_2}$$

(Eq. F-5)

where,

K, E, C_h, F, and %O₂ are defined in section 3.3 of this appendix. When measurements are performed on a wet basis, use the equations in Method 19 in appendix A-7 to part 60 of this chapter.

- 3.2 When the NO_x continuous emission monitoring system uses CO₂ as the diluent, use the following conversion procedure:

$$E = K C_h F_c \frac{100}{\%CO_2}$$

(Eq. F-6)

where:

K, E, C_h, F_c, and %CO₂ are defined in section 3.3 of this appendix.

When CO₂ and NO_x measurements are performed on a different moisture basis, use the equations in Method 19 in appendix A-7 to part 60 of this chapter.

- 3.3 Use the definitions listed below to derive values for the parameters in equations F-5 and F-6 of this appendix, or (if applicable) in the equations in Method 19 in appendix A-7 to part 60 of this chapter.

3.3.1 $K = 1.194 \times 10^{-7}$ (lb/dscf)/ppm NO_x.

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 %O₂, %CO₂ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O₂ or CO₂).

3.3.4.1 For boilers, a minimum concentration of 5.0 percent CO₂ or a maximum concentration of 14.0 percent O₂ may be substituted for the measured diluent gas concentration value for any operating hour in which the hourly average CO₂ concentration is <5.0 percent CO₂ or the hourly average O₂ concentration is >14.0 percent O₂. For stationary gas turbines, a minimum concentration of 1.0 percent CO₂ or a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values for any operating hour in which the hourly average CO₂ concentration is <1.0 percent CO₂ or the hourly average O₂ concentration is >19.0 percent O₂.

3.3.4.2 If NO_x emission rate is calculated using either Equation 19-3 or 19-5 in Method 19 in appendix A-7 to part 60 of this chapter, a variant of the equation shall be used whenever the diluent cap is applied. The modified equations shall be designated as Equations 19-3D and 19-5D, respectively. Equation 19-3D is structurally the same as Equation 19-3, except that the term “%O_{2w}” in the denominator is replaced with the term “%O_{2dc} × [(100-% H₂O)/100]”, where %O_{2dc} is the diluent cap value. The numerator of Equation 19-5D is the same as Equation 19-5; however, the denominator of Equation 19-5D is simply “20.9-%O_{2dc}”, where %O_{2dc} is the diluent cap value.

3.3.5 F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO₂ generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

TABLE 1—F- AND F_c-FACTORS ¹

Fuel	F-factor (dscf/mmBtu)	F _c -factor (scf CO ₂ /mmBtu)
Coal (as defined by ASTM D388-99 ²):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920

¹ Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

² Incorporated by reference under § 75.6 of this part.

Fuel	F-factor (dscf/mmBtu)	F _C -factor (scf CO ₂ /mmBtu)
Wood residue	9,240	1,830

¹ Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

² Incorporated by reference under § 75.6 of this part.

3.3.6 Equations F-7a and F-7b may be used in lieu of the F or F_C factors specified in Section 3.3.5 of this appendix to calculate a site-specific dry-basis F factor (dscf/mmBtu) or a site-specific F_C factor (scf CO₂/mmBtu), on either a dry or wet basis. At a minimum, the site-specific F or F_C factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F or F_C factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F or F_C value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F or F_C determinations, active for at least 3 years. (Calculate all F- and F_C factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

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

(Eq. F-7a)

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

(Eq. F-7b)

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, (solid fuels), ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, (liquid fuels) or computed from results using ASTM D1945-96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, or ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformulated Gas by Gas Chromatography, (gaseous fuels) as applicable. (All of these methods are incorporated by reference under § 75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865-01a or ASTM D5865-10, ASTM D240-00 or ASTM D4809-00, and ASTM D3588-98, ASTM D4891-89 (Reapproved 2006), GPA Standard 2172-96, GPA Standard 2261-00, or ASTM D1826-94 (Reapproved 1998), as applicable. (All of these methods are incorporated by reference under § 75.6.)

3.3.6.3 For affected units that combust a combination of a fuel (or fuels) listed in Table 1 in section 3.3.5 of this appendix with any fuel(s) not listed in Table 1, the F or F_c value is subject to the Administrator's approval under § 75.66.

3.3.6.4 For affected units that combust combinations of fuels listed in Table 1 in section 3.3.5 of this appendix, prorate the F or F_c factors determined by section 3.3.5 or 3.3.6 of this appendix in accordance with the applicable formula as follows:

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

Where,

X_i = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

F_i or $(F_c)_i$ = Applicable F or F_c factor for each fuel type determined in accordance with Section 3.3.5 or 3.3.6 of this appendix.

n = Number of fuels being combusted in combination.

3.3.6.5 As an alternative to prorating the F or F_c factor as described in section 3.3.6.4 of this appendix, a "worst-case" F or F_c factor may be reported for any unit operating hour. The worst-case F or F_c factor shall be the highest F or F_c value for any of the fuels combusted in the unit.

3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^n \frac{E_i}{n} \quad (\text{Eq. F-9})$$

Where:

E_q = Quarterly average NO_x emission rate, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^m \frac{E_i}{m} \quad (\text{Eq. F-10})$$

Where:

E_a = Average NO_x emission rate for the calendar year, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.

m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_x emission rates to the nearest 0.001 lb/mmBtu.

4. Procedures for CO_2 Mass Emissions

Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 or O_2 pollutant monitor) and a flow monitoring system to monitor CO_2 emissions from an affected unit.

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$$E_h = KC_h Q_h \quad (\text{Eq. F-11})$$

Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.

$K = 5.7 \times 10^{-7}$ for CO_2 , (tons/scf) /% CO_2 .

C_h = Hourly average CO_2 concentration during unit operation, wet basis, either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation F-14b, percent CO_2 .

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2 , where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2 .

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{\text{CO}_2q} = \sum_{h=1}^{H_R} E_h t_h \quad (\text{Eq. F-12})$$

Where:

E_{CO_2q} = Quarterly total CO_2 mass emissions, tons.

E_h = Hourly CO_2 mass emission rate, tons/hr.

t_h = Unit operating time, in hours or 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).

H_R = Number of hourly CO₂ mass emission rates available during calendar quarter.

$$E_{CO_2a} = \sum_{q=1}^4 E_{CO_2q} \quad (\text{Eq. F-13})$$

Where:

E_{CO_2a} = Annual total CO₂ mass emissions, tons.

E_{CO_2q} = Quarterly total CO₂ mass emissions, tons.

q = Quarters for which E_{CO_2q} are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O₂ concentration (in percent by volume) of flue gases using an O₂ monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO₂ mass emissions (in tons).

4.4.1 If the owner or operator elects to use data from an O₂ monitor to calculate CO₂ concentration, the appropriate F and F_c factors from section 3.3.5 of this appendix shall be used in one of the following equations (as applicable) to determine hourly average CO₂ concentration of flue gases (in percent by volume) from the measured hourly average O₂ concentration:

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \quad (\text{Eq. F-14a})$$

Where:

CO_{2d} = Hourly average CO₂ concentration during unit operation, percent by volume, dry basis.

F, F_c = F -factor or carbon-based F_c -factor from section 3.3.5 of this appendix.

20.9 = Percentage of O₂ in ambient air.

O_{2d} = Hourly average O₂ concentration during unit operation, percent by volume, dry basis.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \% H_2O}{100} \right) - O_{2w} \right] \quad (\text{Eq. F-14b})$$

Where:

CO_{2w} = Hourly average CO₂ concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O₂ concentration during unit operation, percent by volume, wet basis.

F, F_c = F -factor or carbon-based F_c -factor from section 3.3.5 of this appendix.

20.9 = Percentage of O₂ in ambient air.

%H₂O = Moisture content of gas in the stack, percent.

For any hour where Equation F-14a or F-14b results in a negative hourly average CO₂ value, 0.0% CO_{2w} shall be recorded as the average CO₂ value for that hour.

- 4.4.2 Determine CO₂ mass emissions (in tons) from hourly average CO₂ concentration (percent by volume) using equation F-11 and the procedure in section 4.1, where O₂ measurements are on a wet basis, or using the procedures in section 4.2 of this appendix, where O₂ measurements are on a dry basis.

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

- 5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in § 75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.
- 5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O₂ or CO₂) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

- 5.2.1 When measurements of CO₂ concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \quad (\text{Eq. F-15})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO_{2w} = Hourly concentration of CO₂ during unit operation, percent CO₂ wet basis.

- 5.2.2 When measurements of CO₂ concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c} \right] \left(\frac{\%CO_{2d}}{100} \right) \quad (\text{Eq. F-16})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO_{2d} = Hourly concentration of CO₂ during unit operation, percent CO₂ dry basis.

%H₂O = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O₂ concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9} \quad (\text{Eq. F-17})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

%O_{2w} = Hourly concentration of O₂ during unit operation, percent O₂ wet basis. For any operating hour where Equation F-17 results in an hourly heat input rate that is ≤0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

%H₂O = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O₂ concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100 F} \right] \left[\frac{(20.9 - \%O_{2d})}{20.9} \right] \quad (\text{Eq. F-18})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

%H₂O = Moisture content of the stack gas, percent.

%O_{2d} = Hourly concentration of O₂ during unit operation, percent O₂ dry basis.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{\text{hour}=1}^n HI_i t_i \quad (\text{Eq. F-18a})$$

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_i = Hourly heat input rate during unit operation, using Equation F-15, F-16, F-17, or F-18, mmBtu/hr.

t_i = Hourly operating time for the unit or common stack, hour or 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).

- 5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \quad (\text{Eq. F-18b})$$

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

- 5.3.3 Calculate total daily heat input for a unit using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_d = \sum_{h=1}^{24} HI_h t_h$$

(Eq. F-18c)

Where:

HI_d = Total heat input for a unit for the day, mmBtu.

HI_h = Heat input rate for the unit for hour "h" from Equation F-15, F-16, F-17, F-18, F-21a, or F-21b to this appendix, mmBtu/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

5.4 [Reserved]

- 5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO₂ emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_x mass emissions under a State or federal NO_x mass emission reduction program.

5.5.1

- (a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \quad (\text{Eq. F-19})$$

Where:

HI_o = Hourly heat input rate from oil, mmBtu/hr.

M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o = Gross calorific value of oil, as measured by ASTM D240-00, ASTM D5865-01a, ASTM D5865-10, or ASTM D4809-00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under § 75.6).

10⁶ = Conversion of Btu to mmBtu.

- (b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in § 75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

- 5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \quad (\text{Eq. F-20})$$

Where:

HI_g = Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g = Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826-94 (Reapproved 1998), ASTM D3588-98, ASTM D4891-89 (Reapproved 2006), GPA Standard 2172-96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under § 75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1-5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under § 75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234-00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under § 75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in § 75.36, use of ASTM D2234-00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under § 75.6. Use ASTM D2013-01 for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865-01a or ASTM D5865-10. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§ 75.23 and 75.66.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \quad (\text{Eq. F-21})$$

(Eq. F-21)

where:

HI_c = Daily heat input from coal, mmBtu/day.

M_c = Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c = Gross calorific value of coal sample, as measured by ASTM D3176-89 (Reapproved 2002), ASTM D5865-01a, or ASTM D5865-10, Btu/lb (incorporated by reference under § 75.6).

500 = Conversion of Btu/lb to mmBtu/ton.

- 5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F-21.
- 5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.
- 5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.
- 5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

- 5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{MW_i t_i}{\sum_{i=1}^n MW_i t_i} \right] \quad (\text{Eq. F-21a})$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i = Gross electrical output, MWe.

t_i = Unit operating time, hour or 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).

t_{CS} = Common stack or common pipe operating time, hour or 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).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

- 5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{SF_i t_i}{\sum_{i=1}^n SF_i t_i} \right] \quad (\text{Eq. F-21b})$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

t_i = Unit operating time, hour or 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).

t_{CS} = Common stack or common pipe operating time, hour or 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).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^n HI_s t_s}{t_{Unit}} \quad (\text{Eq. F-21c})$$

Where:

HI_{Unit} = Heat input rate for a unit, mmBtu/hr.

HI_s = Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit} = Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s = Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F-21a or F-21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

$$HI_i = HI_{CP} \left(\frac{t_{CP}}{t_i} \right) \left[\frac{FF_i t_i}{\sum_{i=1}^n FF_i t_i} \right] \quad (\text{Eq. F-21d})$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CP} = Heat input rate at the common pipe, mmBtu/hr.

FF_i = Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

t_i = Unit operating time, hour or 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).

t_{CP} = Common pipe operating time, hour or 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).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

6. Procedure for Converting Volumetric Flow to STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$$F_{STP} = F_{Actual}(T_{Std}/T_{Stack})(P_{Stack}/P_{Std})$$

where:

F_{STP} = Flue gas volumetric flow rate at standard temperature and pressure, scfh.

F_{Actual} = Flue gas volumetric flow rate at actual temperature and pressure, acfh.

T_{Std} = Standard temperature = 528 °R.

T_{Stack} = Flue gas temperature at flow monitor location, °R, where °R = 460 + °F.

P_{Stack} = The absolute flue gas pressure = barometric pressure at the flow monitor location + flue gas static pressure, inches of mercury.

P_{Std} = Standard pressure = 29.92 inches of mercury.

7. Procedures for SO₂ Mass Emissions, Using Default SO₂ Emission Rates and Heat Input Measured by CEMS

The owner or operator shall use Equation F-23 to calculate hourly SO₂ mass emissions in accordance with § 75.11(e)(1) during the combustion of gaseous fuel, for a unit that uses a flow monitor and a diluent gas monitor to measure heat input, and that qualifies to use a default SO₂ emission rate under section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. Equation F-23 may also be applied to the combustion of solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, combinations of such fuels, or mixtures of such fuels with gaseous fuel, if the owner or operator has received approval from the Administrator under § 75.66 to use a site-specific default SO₂ emission rate for the fuel or mixture of fuels.

$$E_h = (ER)(HI) \quad (\text{Eq. F-23})$$

Where:

E_h = Hourly SO₂ mass emission rate, lb/hr.

ER = Applicable SO₂ default emission rate for gaseous fuel combustion, from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, or other default SO₂ emission rate for the combustion of very low sulfur liquid or solid fuel, combinations of such fuels, or mixtures of such fuels with gaseous fuel, as approved by the Administrator under § 75.66, lb/mmBtu.

HI = Hourly heat input rate, determined using the procedures in section 5.2 of this appendix, mmBtu/hr.

8. Procedures for NO_x MASS EMISSIONS

The owner or operator of a unit that is required to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3 of this appendix, as applicable, to account for hourly NO_x mass emissions, and the procedures in section 8.4 of this appendix to account for quarterly, seasonal, and annual NO_x mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 The owner or operator may use the hourly NO_x emission rate and the hourly heat input rate to calculate the NO_x mass emissions in pounds or the NO_x mass emission rate in pounds per hour, (as required by the applicable reporting format), for each unit or stack operating hour, as follows:

8.1.1 If both NO_x emission rate and heat input rate are monitored at the same unit or stack level (e.g., the NO_x emission rate value and the heat input rate value both represent all of the units exhausting to the common stack), then (as required by the applicable reporting format) either:

(a) Use Equation F-24 to calculate the hourly NO_x mass emissions (lb).

$$M_{(NO_x)_h} = ER_{(NO_x)_h} HI_h t_h \quad (\text{Eq. F-24})$$

Where:

$M_{(NO_x)_h}$ = NO_x mass emissions in lbs for the hour.

$ER_{(NO_x)_h}$ = Hourly average NO_x emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A-7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_x emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h, in hours or 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). If the combined NO_x emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack; or

(b) Use Equation F-24a to calculate the hourly NO_x mass emission rate (lb/hr).

$$E_{(NO_x)_h} = ER_{(NO_x)_h} HI_h \quad (\text{Eq. F-24a})$$

Where:

$E_{(NO_x)_h}$ = NO_x mass emissions rate in lbs/hr for the hour.

$ER_{(NO_x)_h}$ = Hourly average NO_x emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A-7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_x emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

- 8.1.2 If NO_x emission rate is measured at a common stack and heat input rate is measured at the unit level, calculate the hourly heat input rate at the common stack according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^p HI_u t_u}{t_{CS}} \quad (\text{Eq. F-25})$$

where:

HI_{CS} = Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS} = Common stack operating time for hour h, in hours or 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). (For each hour, t_{CS} is the total time during which one or more of the units which exhaust through the common stack operate.).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h, in hours or 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).

p = Number of units that exhaust through the common stack.

u = Designation of a particular unit.

Use the hourly heat input rate at the common stack level and the hourly average NO_x emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_x mass emissions at the common stack.

- 8.1.3 If a unit has multiple ducts and NO_x emission rate is only measured at one duct, use the NO_x emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_x mass emissions.
- 8.1.4 If a unit has multiple ducts and NO_x emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_x mass emissions.

8.2 Alternatively, the owner or operator may use the hourly NO_x concentration (as measured by a NO_x concentration monitoring system) and the hourly stack gas volumetric flow rate to calculate the NO_x mass emission rate (lb/hr) for each unit or stack operating hour, in accordance with section 8.2.1 or 8.2.2 of this appendix (as applicable). If the hourly NO_x mass emissions are to be reported in lb, Equation F-26c in section 8.3 of this appendix shall be used to convert the hourly NO_x mass emission rates to hourly NO_x mass emissions (lb).

8.2.1 When the NO_x concentration monitoring system measures on a wet basis, first calculate the hourly NO_x mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26a. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(\text{NO}_x)_h} = K C_{hw} Q_h \quad (\text{Eq. F-26a})$$

Where:

$E_{(\text{NO}_x)_h}$ = NO_x mass emissions rate in lb/hr.

$K = 1.194 \times 10^{-7}$ for NO_x, (lb/scf)/ppm.

C_{hw} = Hourly average NO_x concentration during unit operation, wet basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

8.2.2 When NO_x mass emissions are determined using a dry basis NO_x concentration monitoring system and a wet basis flow monitoring system, first calculate hourly NO_x mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F-26b. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(\text{NO}_x)_h} = K C_{hd} Q_h \frac{(100 - \%H_2O)}{(100)} \quad (\text{Eq. F-26b})$$

Where:

$E_{(\text{NO}_x)_h}$ = NO_x mass emissions rate, lb/hr.

$K = 1.194 \times 10^{-7}$ for NO_x, (lb/scf)/ppm.

C_{hd} = Hourly average NO_x concentration during unit operation, dry basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

8.3 When hourly NO_x mass emissions are reported in pounds and are determined using a NO_x concentration monitoring system and a flow monitoring system, calculate NO_x mass emissions (lb) for each unit or stack operating hour by multiplying the hourly NO_x mass emission rate (lb/hr) by the unit operating time for the hour, as follows:

$$M_{(NO_x)_h} = E_h t_h \quad (\text{Eq. F-26c})$$

Where:

$M_{(NO_x)_h}$ = NO_x mass emissions for the hour, lb.

E_h = Hourly NO_x mass emission rate during unit (or stack) operation from Equation F-26a in section 8.2.1 of this appendix or Equation F-26b in section 8.2.2 of this appendix (as applicable), lb/hr.

t_h = Unit operating time or stack operating time (as defined in § 72.2 of this chapter) for hour “h”, in hours or 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).

8.4 Use the following equations to calculate daily, quarterly, cumulative ozone season, and cumulative year-to-date NO_x mass emissions:

(a) When hourly NO_x mass emissions are reported in lb., use Eq. F-27 to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_x mass emissions in tons.

$$M_{(NO_x)_{\text{time period}}} = \frac{\sum_{h=1}^p M_{(NO_x)_h}}{2000} \quad (\text{Eq. F-27})$$

Where:

$M_{(NO_x)_{\text{time period}}}$ = NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NO_x)_h}$ = NO_x mass emissions in lb for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

(b) When hourly NO_x mass emission rate is reported in lb/hr, use Eq. F-27a to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_x mass emissions in tons.

$$M_{(NO_x)_{\text{time period}}} = \frac{\sum_{h=1}^p E_{(NO_x)_h} t_h}{2000} \quad (\text{Eq. F-27a})$$

Where:

$M_{(NO_x)_{\text{time period}}}$ = NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$E_{(NO_x)_h}$ = NO_x mass emission rate in lb/hr for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

t_h = Monitoring location operating time for hour h, in hours or 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).

- (c) To calculate daily NO_x mass emissions for a unit in pounds, use Eq. F-27b to this appendix.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h} t_h$$

(Eq. F-27b)

Where:

M_{(NOX)_d} = NO_x mass emissions for a unit for the day, pounds.

E_{(NOX)_h} = NO_x mass emission rate for the unit for hour “h” from Equation F-24a, F-26a, F-26b, or F-28, lb/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

- 8.5 Specific provisions for monitoring NO_x mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_x mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_x mass reduction program:
- 8.5.1 The owner or operator may determine both NO_x emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_x mass emissions at the common stack.
- 8.5.2 The owner or operator may determine the NO_x emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_x mass emissions at the common stack.
- 8.5.3 Where applicable, the owner or operator of a unit that determines hourly NO_x mass emission rate at a common stack shall apportion hourly NO_x mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F-28 to this appendix:

$$E_{(NOX)_i} = E_{(NOX)CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{HI_i t_i}{\sum_{i=1}^n HI_i t_i} \right]$$

(Eq. F-28)

Where:

$E_{(NOX)_i}$ = Apportioned NO_x mass emission rate for the hour for unit “i”, lb/hr.

$E_{(NOX)CS}$ = NO_x mass emission rate for the hour at the common stack, lb/hr.

HI_i = Heat input rate for the hour for unit “i,” from Equation F-15, F-16, F-17, F-18, F-21a, or F-21b to this appendix, mmBtu/hr.

t_i = Operating time for unit “i”, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Common stack operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of units using the common stack.

i = Designation of a particular unit.

9. [Reserved]

10. Moisture Determination From Wet and Dry O_2 Readings

If a correction for the stack gas moisture content is required in any of the emissions or heat input calculations described in this appendix, and if the hourly moisture content is determined from wet- and dry-basis O_2 readings, use Equation F-31 to calculate the percent moisture, unless a “K” factor or other mathematical algorithm is developed as described in section 6.5.7(a) of appendix A to this part:

$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100 \quad (\text{Eq. F-31})$$

Where:

% H_2O = Hourly average stack gas moisture content, percent H_2O

O_{2d} = Dry-basis hourly average oxygen concentration, percent O_2

O_{2w} = Wet-basis hourly average oxygen concentration, percent O_2

[58 FR 3701, Jan. 11, 1993; Redesignated and amended at 60 FR 26553, 26571, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28666, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40474, 40475, June 12, 2002; 67 FR 53505, Aug. 16, 2002; 70 FR 28695, May 18, 2005; 73 FR 4372, Jan. 24, 2008; 76 FR 17325, Mar. 28, 2011; 77 FR 2460, Jan. 18, 2012; 88 FR 36896, June 5, 2023]

Appendix G to Part 75—Determination of CO₂ Emissions

1. Applicability

The procedures in this appendix may be used to estimate CO₂ mass emissions discharged to the atmosphere (in tons/day) as the sum of CO₂ emissions from combustion and, if applicable, CO₂ emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

2. Procedures for Estimating CO₂ Emissions From Combustion

Use the following procedures to estimate daily CO₂ mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO₂ continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO₂ emissions.

- 2.1 Use the following equation to calculate daily CO₂ mass emissions (in tons/day) from the combustion of fossil fuels. Where fuel flow is measured in a common pipe header (i.e., a pipe carrying fuel for multiple units), the owner or operator may use the procedures in section 2.1.2 of appendix D of this part for combining or apportioning emissions, except that the term “SO₂ mass emissions” is replaced with the term “CO₂ mass emissions.”

$$W_{CO_2} = \frac{(MW_C + MW_{O_2}) \times W_C}{2,000 MW_C} \text{ (Eq. G-1)}$$

Where:

W_{co2} = CO₂ emitted from combustion, tons/day.

MW_c = Molecular weight of carbon (12.0).

MW_{o2} = Molecular weight of oxygen (32.0)

W_c = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

- 2.1.1 Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of appendix D to this part, and one sample per month for each gaseous fuel that is required to be

sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of appendix D to this part. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week.

2.1.2 Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178-89 (Reapproved 2002) or ASTM D5373-02 (Reapproved 2007) for coal; ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil, or computations based upon ASTM D3238-95 (Reapproved 2000) and either ASTM D2502-92 (Reapproved 1996) or ASTM D2503-92 (Reapproved 1997) for oil; and computations based on ASTM D1945-96 (Reapproved 2001) or ASTM D1946-90 (Reapproved 2006) for gas (all incorporated by reference under § 75.6 of this part).

2.1.3 Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6.) Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

2.2 For an affected coal-fired unit, the estimate of daily CO₂ mass emissions given by equation G-1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.2.1 through 2.2.3 or section 2.2.4 of this appendix.

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174-00, "Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal" (incorporated by reference under § 75.6 of this part).

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D5373-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke" (incorporated by reference under § 75.6 of this part).

2.2.3 Discount the estimate of daily CO₂ mass emissions from the combustion of coal given by equation G-1 by the percent carbon retained in the ash using the following equation:

$$W_{\text{NetCO}_2} = W_{\text{CO}_2} - \left(\frac{MW_{\text{CO}_2}}{MW_c} \right) \left(\frac{A\%}{100} \right) \left(\frac{C\%}{100} \right) W_{\text{COAL}}$$

(Eq. G-2)

where,

W_{NetCO_2} = Net CO₂ mass emissions discharged to the atmosphere, tons/day.

W_{CO_2} = Daily CO₂ mass emissions calculated by equation G-1, tons/day.

MW_{CO_2} = Molecular weight of carbon dioxide (44.0).

MW_c = Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

W_{COAL} = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$$W_{\text{NCO}_2} = .99 W_{\text{CO}_2}$$

(Eq. G-3)

where,

W_{NCO_2} = Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO_2 upon combustion.

W_{CO_2} = Daily CO_2 mass emissions from the combustion of coal calculated by equation G-1, tons/day.

2.3 In lieu of using the procedures, methods, and equations in section 2.1 of this appendix, the owner or operator of an affected gas-fired or oil-fired unit (as defined under § 72.2 of this chapter) may use the following equation and records of hourly heat input to estimate hourly CO_2 mass emissions (in tons).

$$W_{\text{CO}_2} = \left(\frac{F_C \times H \times U_f \times \text{MW}_{\text{CO}_2}}{2000} \right) \quad (\text{Eq. G-4})$$

(Eq. G-4)

Where:

W_{CO_2} = CO_2 emitted from combustion, tons/hr.

MW_{CO_2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_C = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F to this part for other gaseous fuels.

H = Hourly heat input in mmBtu, as calculated using the procedures in section 5 of appendix F of this part.

U_f = 1/385 scf CO_2 /lb-mole at 14.7 psia and 68 °F.

3. Procedures for Estimating CO_2 Emissions From Sorbent

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO₂ continuous emission monitoring system or an O₂ monitor and a flow monitor, or use the procedures, methods, and equations in sections 3.1 through 3.2 of this appendix to determine daily CO₂ mass emissions from the sorbent (in tons).

3.1 When limestone is the sorbent material, use the equations and procedures in either section 3.1.1 or 3.1.2 of this appendix.

3.1.1 Use the following equation to estimate daily CO₂ mass emissions from sorbent (in tons).

$$SE_{CO_2} = W_{CaCO_3} F_u \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

(Eq. G-5)

where,

SE_{CO2} = CO₂ emitted from sorbent, tons/day.

W_{CaCO3} = CaCO₃ used, tons/day.

F_u = 1.00, the calcium to sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_{CaCO3} = Molecular weight of calcium carbonate (100).

3.1.2 In lieu of using Equation G-5, any owner or operator who operates and maintains a certified SO₂-diluent continuous emission monitoring system (consisting of an SO₂ pollutant concentration monitor and an O₂ or CO₂ diluent gas monitor), for measuring and recording SO₂ emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations such as those in EPA Method 19 in appendix A to part 60 of this chapter to estimate the SO₂ emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO₂ mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_u \frac{W_{SO_2}}{2000} \frac{MW_{CO_2}}{MW_{SO_2}}$$

(Eq. G-6)

where,

SE_{CO2} = CO₂ emitted from sorbent, tons/day.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_{SO_2} = Molecular weight of sulfur dioxide (64).

W_{SO_2} = Sulfur dioxide removed, lb/day, as calculated below using Eq. G-7.

$F_u = 1.0$, the calcium to sulfur stoichiometric ratio.

and

$$W_{SO_2} = SO_{20} \frac{\%R}{(100 - \%R)} \quad (\text{Eq. G-7})$$

(Eq. G-7)

where:

W_{SO_2} = Weight of sulfur dioxide removed, lb/day.

SO_{20} = SO_2 mass emissions monitored at the outlet, lb/day, as calculated using the equations and procedures in section 2 of appendix F of this part.

$\%R$ = Overall percentage SO_2 emissions removal efficiency, calculated using equations such as those in EPA Method 19 in appendix A to part 60 of this chapter, and using daily instead of annual average emission rates.

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in section 3.1 of this appendix as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F_u , defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2 , using methods and procedures satisfactory to the Administrator. Use this value of F_u (instead of 1.0) in either equation G-5 or equation G-6.

3.2.2 When using equation G-5, replace MW_{CaCO_3} , the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2 , and replace W_{CaCO_3} , the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

4. Procedures for Estimating Total CO_2 Emissions

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

$$W_t = W_{CO_2} + SE_{CO_2}$$

(Eq. G-8)

where,

W_t = Estimated total CO_2 mass emissions, tons/day.

W_{CO_2} = CO₂ emitted from fuel combustion, tons/day.

SE_{CO_2} = CO₂ emitted from sorbent, tons/day.

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO₂ mass emissions under this appendix.

5.1-5.1.2 [Reserved]

5.2 Missing Carbon Content Data

Use the following procedures to substitute for missing carbon content data.

- 5.2.1 In all cases (i.e., for weekly coal samples or composite oil samples from continuous sampling, for oil samples taken from the storage tank after transfer of a new delivery of fuel, for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, and for gaseous fuel that is supplied by a pipeline and sampled monthly, daily or hourly for gross calorific value) when carbon content data is missing, report the appropriate default value from Table G-1.
- 5.2.2 The missing data values in Table G-1 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G-1. -- MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Missing data value
Oil and coal carbon content	Most recent, previous carbon content value available for that type of coal, grade of oil, or default value, in this table
Gas carbon content	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table
Default coal carbon content	Anthracite: 90.0 percent
	Bituminous: 85.0 percent
	Subbituminous/Lignite: 75.0 percent
Default oil carbon content	90.0 percent
Default gas carbon content	Natural gas: 75.0 percent
	Other gaseous fuels: 90.0 percent

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO₂ emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26556, May 17, 1995; 61 FR 25585, May 22, 1996; 64 FR 28671, May 26, 1999; 67 FR 40475, June 12, 2002; 67 FR 57274, Sept. 9, 2002; 73 FR 4376, Jan. 24, 2008]

Appendix H to Part 75—Revised Traceability Protocol No. 1 [Reserved]

Appendix I to Part 75—Optional F—Factor/Fuel Flow Method [Reserved]

Appendix J to Part 75—Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures [Reserved]

Appendix C

Compliance Plan for SN-03, Maintenance Plan for SN-04, and Design



Entergy Services, Inc.
225 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203
Tel 501-377-4032
Fax 501-377-5656

AR-01-068

May 30, 2001

State of Arkansas
Department of Environmental Quality
Air Division
ATTN: Compliance Inspector Supervisor
8001 National Drive
Post Office Box 8913
Little Rock, Arkansas 72219-8913

Dear Sirs,

Subject: Independence Plant-Permit 449-AOP-R0
Update compliance plan for the rotary car dumper (SN-03)

In accordance with the Title V minor modification request approval received on May 17, 2001, Entergy is submitting the following revised compliance plan for the rotary car dumper for your review and approval. This plan will replace the previous compliance plan included in Appendix C of the permit. The change in the maintenance plan is necessary because the new dust suppression system is completely different from the old system. The old system was based on the use of rotoclones. The new system is based on the use of a foam spray.

Requirements include but are not limited to the following:

- a. Inspect spray nozzles for pluggage.
- b. Check air pressure and flow.
- c. Check water pressure and water/dust/foam flow.
- d. Check for adequate dustfoam chemical additive.

SPECIAL INSTRUCTIONS for PM #3641 (Printed: 6/10/03)

(M641)

AIR PERMIT requires this checklist be filed and retained. Return this checklist to the Environmental Specialist upon completion.

BAGHOUSE

CHECK AIR LEAKS ON PULSATION SYSTEM

CHECK AIR OPERATED VALVES

CHECK PIPING & SUPPORTS

CHECK AIR CYLINDERS

CHECK BAGHOUSE DOORS & SEALS

CHECK BAGS

CHECK PULSATION TUBES

CHECK DIFFUSER BLOWER BEARINGS FOR HEAT AND VIBRATION

CHECK BLOWER CASE FOR EXCESSIVE HEAT BUILDUP

CHECK INLET FILTER AND CHANGE AS NEEDED

****WRITE WR AS NEEDED****

PERFORMED BY _____ DATE _____
FILE _____ NOT FILE _____

REVIEWED BY _____ DATE _____

REVIEWED _____ DATE _____

Technical Design Data

Cooling Tower	
Manufacturer	Research-Cottrell Hamon Cooling Tower Division
Type	Natural Draft
Tower Construction	Hyperbolic
Water Flow @ 100%	360,000 gpm
Water Flow @ 50%	180,000 gpm
Fill	Asbestos Cement
Drift Eliminators	Asbestos Cement
Heat Load	4.36×10^9 btu/hr
Range	28.1°F
Wet Bulb	78°F
Dry Bulb	94°F
Cold Water	95°F
Approach	17°F
Relative Humidity	50%
Evaporative Loss (Percent of circulating water flow)	2.46%
Drift Loss (Percent of circulating water flow)	.01%

Appendix D

Acid Rain Permit Application



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	Independence	State	AR	Plant Code	6641

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)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Independence

 Facility (Source) Name (from STEP 1)
STEP 3**Permit Requirements****Read the standard 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) Independence

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)	Independence

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	Susan Margaret Floyd	
Signature		Date 10/9/25

Appendix E

Cross-State Air Pollution Rule Forms and Information

Transport Rule (TR) Trading Program Title V Requirements

Description of TR Monitoring Provisions

The TR subject unit(s), and the unit-specific monitoring provisions at this source, are identified in the following table(s). These unit(s) are subject to the requirements for the TR NO_x Ozone Season Group 2 Trading Program.

[Complete a separate table for each TR-subject unit, with the unit ID inserted in the second row. In each unit's separate table, insert a "✓" in each applicable column for each applicable parameter to reflect the monitoring methodology used at that unit for that parameter.]

AFIN: 32-00042			Date: 09/26/2025		
Unit ID: Unit 1 Boiler (SN-01)					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	✓		-----		
NO _x	✓	-----			
Heat input	✓		-----		

AFIN: 32-00042			Date: 09/26/2025		
Unit ID: Unit 2 Boiler (SN-02)					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO ₂ monitoring) and 40 CFR part 75, subpart H (for NO _x monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO ₂	✓		-----		
NO _x	✓	-----			
Heat input	✓		-----		

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 C.F.R. §§ 97.830 through 97.835 (TR NO_x Ozone Season Group 2 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit will be included in the conditions of the permit.
2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 C.F.R. §§ 75.53, 75.62 and 75.73, as applicable.
3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 C.F.R. § 75 Subpart E and 40 C.F.R. §§ 75.66 and 97.835 (TR NO_x Ozone Season Group 2 Trading Program).
4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 C.F.R. §§ 97.830 through 97.834 (TR NO_x Ozone Season Group 2 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 C.F.R. §§ 75.66 and 97.835 (TR NO_x Ozone Season Group 2 Trading Program).
5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 C.F.R. §§ 97.830 through 97.834 (TR NO_x Ozone Season Group 2 Trading Program), and therefore minor permit modification procedures, in accordance with 40 C.F.R. §§ 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

Appendix F

40 C.F.R. § 60, Subpart Y – *Standards of Performance for Coal Preparation Plants*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart Y Standards of Performance for Coal Preparation and Processing Plants

- § 60.250 Applicability and designation of affected facility.
- § 60.251 Definitions.
- § 60.252 Standards for thermal dryers.
- § 60.253 Standards for pneumatic coal-cleaning equipment.
- § 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.
- § 60.255 Performance tests and other compliance requirements.
- § 60.256 Continuous monitoring requirements.
- § 60.257 Test methods and procedures.
- § 60.258 Reporting and recordkeeping.

Subpart Y—Standards of Performance for Coal Preparation and Processing Plants

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

§ 60.250 Applicability and designation of affected facility.

- (a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.
- (b) The provisions in §§ 60.251, 60.252(a), 60.253(a), 60.254(a), 60.255(a), and 60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.
- (c) The provisions in §§ 60.251, 60.252(b)(1) and (c), 60.253(b), 60.254(b), 60.255(b) through (h), 60.256(b) and (c), 60.257, and 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

- (d) The provisions in §§ 60.251, 60.252(b)(1) through (3), and (c), 60.253(b), 60.254(b) and (c), 60.255(b) through (h), 60.256(b) and (c), 60.257, and 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

§ 60.251 Definitions.

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

- (a) **Anthracite** means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).
- (b) **Bag leak detection system** means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.
- (c) **Bituminous coal** means solid fossil fuel classified as bituminous coal by ASTM D388 (incorporated by reference—see § 60.17).
- (d) **Coal** means:
 - (1) For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference—see § 60.17).
 - (2) For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference—see § 60.17), and coal refuse.
- (e) **Coal preparation and processing plant** means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.
- (f) **Coal processing and conveying equipment** means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.
- (g) **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.
- (h) **Coal storage system** means any facility used to store coal except for open storage piles.
- (i) **Design controlled potential PM emissions rate** means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

- (j) **Indirect thermal dryer** means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.
- (k) **Lignite** means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).
- (l) **Mechanical vent** means any vent that uses a powered mechanical drive (machine) to induce air flow.
- (m) **Open storage pile** means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.
- (n) **Operating day** means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.
- (o) **Pneumatic coal-cleaning equipment** means:
 - (1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).
 - (2) For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).
- (p) **Potential combustion concentration** means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A-7 of this part.
- (q) **Subbituminous coal** means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).
- (r) **Thermal dryer** means:
 - (1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.
 - (2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.
- (s) **Transfer and loading system** means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for thermal dryers.

- (a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

- (1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and
- (2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide (SO₂), and combined nitrogen oxides (NO_x) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

- (1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.
 - (i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).
 - (A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and
 - (B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.
 - (ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.
 - (A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and
 - (B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.
- (2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for SO₂ emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.
 - (i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or
 - (ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain SO₂ in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO₂ in excess of 10 percent of the potential combustion concentration (*i.e.*, the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

- (iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an SO₂ limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the SO₂ limits of this section.
- (3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined NO_x and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.
 - (i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of NO_x and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.
 - (ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of NO_x and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.
 - (iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a NO_x limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined NO_x and CO limits of this section.
- (c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

§ 60.253 Standards for pneumatic coal-cleaning equipment.

- (a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.
 - (1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and
 - (2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.
- (b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.
 - (1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess or 0.023 g/dscm (0.010 gr/dscf); and
 - (2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.

- (a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.
- (b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.
 - (1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.
 - (2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).
 - (3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.
- (c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.
 - (1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.
 - (2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met), use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.
 - (3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.

- (i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.
 - (ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).
 - (iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.
 - (iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.
- (4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.
- (i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.
 - (ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.
- (5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.
- (i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.
 - (ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

- (6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

§ 60.255 Performance tests and other compliance requirements.

- (a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in § 60.257.
- (b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of § 60.8 and the methods identified in § 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.
 - (1) For each affected facility subject to a PM, SO₂, or combined NO_x and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.
 - (i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.
 - (ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.
 - (iii) An owner or operator of 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 30 calendar days after the next operating day.
 - (2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.
 - (i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.
 - (ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

- (iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in § 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.
- (c) If any affected coal processing and conveying equipment (e.g., breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in § 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.
- (d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.
 - (1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,
 - (2) The control device manufacturer's recommended maintenance procedures are followed, and
 - (3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.
- (e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.
 - (1) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;
 - (2) The manufacturer's recommended maintenance procedures are followed for each control device; and
 - (3) A performance test is conducted on each affected facility at least once every 5 calendar years.
- (f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.
 - (1) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.
 - (i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions

observed. Each observer determining the presence of visible emissions must meet the training requirements specified in § 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of this part, performance test must be conducted within 45 operating days.

- (ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.
- (iii) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

- (2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. 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 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. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

- (g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

- (1) The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

- (2) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.

- (i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

- (ii) The owner or operator must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

- (iii) The owner or operator must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.
 - (iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and 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.
 - (v) The owner or operator must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.
- (h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.
- (1) Conduct an initial performance test using Method 9 of appendix A-4 of this part according to the requirements in paragraphs (h)(1)(i) and(ii).
 - (i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.
 - (ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.
 - (2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.
 - (3) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

§ 60.256 Continuous monitoring requirements.

- (a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.
 - (1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:
 - (i) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within $\pm 1.7^{\circ}\text{C}$ ($\pm 3^{\circ}\text{F}$).
 - (ii) For affected facilities that use wet scrubber emission control equipment:

- (A) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 1 inch water gauge.
 - (B) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator shall have discretion to grant requests for approval of alternative monitoring locations.
- (2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).
- (b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.
 - (1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.
 - (2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.
 - (i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 1 inch water gauge.
 - (ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design water supply flow rate.
 - (iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design pH.
 - (iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.
 - (3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.
- (c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

- (1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.
 - (i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.
 - (ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).
 - (iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.
 - (iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.
 - (v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.
 - (vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.
 - (vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.
 - (viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.
- (2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (v) of this section.
 - (i) Installation of the bag leak detection system;
 - (ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;
 - (iii) Operation of the bag leak detection system, including quality assurance procedures;
 - (iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;
 - (v) How the bag leak detection system output will be recorded and stored; and

- (vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.
- (3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:
- (i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;
 - (ii) Sealing off defective bags or filter media;
 - (iii) Replacing defective bags or filter media or otherwise repairing the control device;
 - (iv) Sealing off a defective fabric filter compartment;
 - (v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or
 - (vi) Shutting down the process producing the PM emissions.

§ 60.257 Test methods and procedures.

- (a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.
- (1) Method 9 of appendix A-4 of this part and the procedures in § 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).
- (i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages).
 - (ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.
- (2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.
- (i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.
 - (ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

- (iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.
- (3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.
 - (i) No more than three emissions points may be read concurrently.
 - (ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.
 - (iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.
- (b) The owner or operator must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emissions standards specified in § 60.252 according to the requirements in § 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.
 - (1) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.
 - (2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas.
 - (3) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses (incorporated by reference—see § 60.17) as an alternative to Method 3B of appendix A-2 of this part.
 - (4) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas.
 - (5) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows:
 - (i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test.
 - (ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.
 - (iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.
 - (iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications (e.g., stub stacks and roof vents).

- (v) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.
- (6) Method 6, 6A, or 6C of appendix A-4 of this part shall be used to determine the SO₂ concentration. A minimum of three valid test runs are needed to comprise an SO₂ performance test.
- (7) Method 7 or 7E of appendix A-4 of this part shall be used to determine the NO_x concentration. A minimum of three valid test runs are needed to comprise an NO_x performance test.
- (8) Method 10 of appendix A-4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with NO_x performance tests.

§ 60.258 Reporting and recordkeeping.

- (a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:
 - (1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.
 - (2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.
 - (3) The amount and type of coal processed each calendar month.
 - (4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.
 - (5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.
 - (6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, e.g., objections, to the plan and any actions relative to the alternative control measures, e.g., approvals, shall be noted in the logbook as well.
 - (7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.
 - (i) Records of the bag leak detection system output;

- (ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection settings; and
 - (iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.
- (8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.
- (9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.
- (10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.
- (b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:
 - (1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.
 - (2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.
 - (3) All 6-minute average opacities that exceed the applicable standard.
- (c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.
- (d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main>. For performance tests that cannot be entered into WebFIRE (i.e., Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711.

Appendix G

40 C.F.R. § 61, Subpart M – *National Emissions Standard for Asbestos*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 61 —National Emission Standards for Hazardous Air Pollutants

Authority: 42 U.S.C. 7401 *et seq.*

Source: 38 FR 8826, Apr. 6, 1973, unless otherwise noted.

Subpart M National Emission Standard for Asbestos

§ 61.140 Applicability.

§ 61.141 Definitions.

§ 61.142 Standard for asbestos mills.

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§ 61.144 Standard for manufacturing.

§ 61.145 Standard for demolition and renovation.

§ 61.146 Standard for spraying.

§ 61.147 Standard for fabricating.

§ 61.148 Standard for insulating materials.

§ 61.149 Standard for waste disposal for asbestos mills.

§ 61.150 Standard for waste disposal for manufacturing, fabricating, demolition, renovation, and spraying operations.

§ 61.151 Standard for inactive waste disposal sites for asbestos mills and manufacturing and fabricating operations.

§ 61.152 Air-cleaning.

§ 61.153 Reporting.

§ 61.154 Standard for active waste disposal sites.

§ 61.155 Standard for operations that convert asbestos-containing waste material into nonasbestos (asbestos-free) material.

§ 61.156 Cross-reference to other asbestos regulations.

§ 61.157 Delegation of authority.

Appendix A to Subpart M of Part 61

Interpretive Rule Governing Roof Removal Operations

Subpart M—National Emission Standard for Asbestos

Authority: 42 U.S.C. 7401, 7412, 7414, 7416, 7601.

Source: 49 FR 13661, Apr. 5, 1984, unless otherwise noted.

§ 61.140 Applicability.

The provisions of this subpart are applicable to those sources specified in §§ 61.142 through 61.151, 61.154, and 61.155.

[55 FR 48414, Nov. 20, 1990]

§ 61.141 Definitions.

All terms that are used in this subpart and are not defined below are given the same meaning as in the Act and in subpart A of this part.

Active waste disposal site means any disposal site other than an inactive site.

Adequately wet means sufficiently mix or penetrate with liquid to prevent the release of particulates. If visible emissions are observed coming from asbestos-containing material, then that material has not been adequately wetted. However, the absence of visible emissions is not sufficient evidence of being adequately wet.

Asbestos means the asbestiform varieties of serpentine (chrysotile), riebeckite (crocidolite), cummingtonite-grunerite, anthophyllite, and actinolite-tremolite.

Asbestos-containing waste materials means mill tailings or any waste that contains commercial asbestos and is generated by a source subject to the provisions of this subpart. This term includes filters from control devices, friable asbestos waste material, and bags or other similar packaging contaminated with commercial asbestos. As applied to demolition and renovation operations, this term also includes regulated asbestos-containing material waste and materials contaminated with asbestos including disposable equipment and clothing.

Asbestos mill means any facility engaged in converting, or in any intermediate step in converting, asbestos ore into commercial asbestos. Outside storage of asbestos material is not considered a part of the asbestos mill.

Asbestos tailings means any solid waste that contains asbestos and is a product of asbestos mining or milling operations.

Asbestos waste from control devices means any waste material that contains asbestos and is collected by a pollution control device.

Category I nonfriable asbestos-containing material (ACM) means asbestos-containing packings, gaskets, resilient floor covering, and asphalt roofing products containing more than 1 percent asbestos as determined using the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy.

Category II nonfriable ACM means any material, excluding Category I nonfriable ACM, containing more than 1 percent asbestos as determined using the methods specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy that, when dry, cannot be crumbled, pulverized, or reduced to powder by hand pressure.

Commercial asbestos means any material containing asbestos that is extracted from ore and has value because of its asbestos content.

Cutting means to penetrate with a sharp-edged instrument and includes sawing, but does not include shearing, slicing, or punching.

Demolition means the wrecking or taking out of any load-supporting structural member of a facility together with any related handling operations or the intentional burning of any facility.

Emergency renovation operation means a renovation operation that was not planned but results from a sudden, unexpected event that, if not immediately attended to, presents a safety or public health hazard, is necessary to protect equipment from damage, or is necessary to avoid imposing an unreasonable financial burden. This term includes operations necessitated by nonroutine failures of equipment.

Fabricating means any processing (e.g., cutting, sawing, drilling) of a manufactured product that contains commercial asbestos, with the exception of processing at temporary sites (field fabricating) for the construction or restoration of facilities. In the case of friction products, fabricating includes bonding, debonding, grinding, sawing, drilling, or other similar operations performed as part of fabricating.

Facility means any institutional, commercial, public, industrial, or residential structure, installation, or building (including any structure, installation, or building containing condominiums or individual dwelling units operated as a residential cooperative, but excluding residential buildings having four or fewer dwelling units); any ship; and any active or inactive waste disposal site. For purposes of this definition, any building, structure, or installation that contains a loft used as a dwelling is not considered a residential structure, installation, or building. Any structure, installation or building that was previously subject to this subpart is not excluded, regardless of its current use or function.

Facility component means any part of a facility including equipment.

Friable asbestos material means any material containing more than 1 percent asbestos as determined using the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy, that, when dry, can be crumbled, pulverized, or reduced to powder by hand pressure. If the asbestos content is less than 10 percent as determined by a method other than point counting by polarized light microscopy (PLM), verify the asbestos content by point counting using PLM.

Fugitive source means any source of emissions not controlled by an air pollution control device.

Glove bag means a sealed compartment with attached inner gloves used for the handling of asbestos-containing materials. Properly installed and used, glove bags provide a small work area enclosure typically used for small-scale asbestos stripping operations. Information on glove-bag installation, equipment and supplies, and work practices is contained in the Occupational Safety and Health Administration's (OSHA's) final rule on occupational exposure to asbestos (appendix G to 29 CFR 1926.58).

Grinding means to reduce to powder or small fragments and includes mechanical chipping or drilling.

In poor condition means the binding of the material is losing its integrity as indicated by peeling, cracking, or crumbling of the material.

Inactive waste disposal site means any disposal site or portion of it where additional asbestos-containing waste material has not been deposited within the past year.

Installation means any building or structure or any group of buildings or structures at a single demolition or renovation site that are under the control of the same owner or operator (or owner or operator under common control).

Leak-tight means that solids or liquids cannot escape or spill out. It also means dust-tight.

Malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner so that emissions of asbestos are increased. Failures of equipment shall not be considered malfunctions if they are caused in any way by poor maintenance, careless operation, or any other preventable upset conditions, equipment breakdown, or process failure.

Manufacturing means the combining of commercial asbestos—or, in the case of woven friction products, the combining of textiles containing commercial asbestos—with any other material(s), including commercial asbestos, and the processing of this combination into a product. Chlorine production is considered a part of manufacturing.

Natural barrier means a natural object that effectively precludes or deters access. Natural barriers include physical obstacles such as cliffs, lakes or other large bodies of water, deep and wide ravines, and mountains. Remoteness by itself is not a natural barrier.

Nonfriable asbestos-containing material means any material containing more than 1 percent asbestos as determined using the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy, that, when dry, cannot be crumbled, pulverized, or reduced to powder by hand pressure.

Nonscheduled renovation operation means a renovation operation necessitated by the routine failure of equipment, which is expected to occur within a given period based on past operating experience, but for which an exact date cannot be predicted.

Outside air means the air outside buildings and structures, including, but not limited to, the air under a bridge or in an open air ferry dock.

Owner or operator of a demolition or renovation activity means any person who owns, leases, operates, controls, or supervises the facility being demolished or renovated or any person who owns, leases, operates, controls, or supervises the demolition or renovation operation, or both.

Particulate asbestos material means finely divided particles of asbestos or material containing asbestos.

Planned renovation operations means a renovation operation, or a number of such operations, in which some RACM will be removed or stripped within a given period of time and that can be predicted. Individual nonscheduled operations are included if a number of such operations can be predicted to occur during a given period of time based on operating experience.

Regulated asbestos-containing material (RACM) means

- (a) Friable asbestos material,
- (b) Category I nonfriable ACM that has become friable,
- (c) Category I nonfriable ACM that will be or has been subjected to sanding, grinding, cutting, or abrading, or
- (d) Category II nonfriable ACM that has a high probability of becoming or has become crumbled, pulverized, or reduced to powder by the forces expected to act on the material in the course of demolition or renovation operations regulated by this subpart.

Remove means to take out RACM or facility components that contain or are covered with RACM from any facility.

Renovation means altering a facility or one or more facility components in any way, including the stripping or removal of RACM from a facility component. Operations in which load-supporting structural members are wrecked or taken out are demolitions.

Resilient floor covering means asbestos-containing floor tile, including asphalt and vinyl floor tile, and sheet vinyl floor covering containing more than 1 percent asbestos as determined using polarized light microscopy according to the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy.

Roadways means surfaces on which vehicles travel. This term includes public and private highways, roads, streets, parking areas, and driveways.

Strip means to take off RACM from any part of a facility or facility components.

Structural member means any load-supporting member of a facility, such as beams and load supporting walls; or any nonload-supporting member, such as ceilings and nonload-supporting walls.

Visible emissions means any emissions, which are visually detectable without the aid of instruments, coming from RACM or asbestos-containing waste material, or from any asbestos milling, manufacturing, or fabricating operation. This does not include condensed, uncombined water vapor.

Waste generator means any owner or operator of a source covered by this subpart whose act or process produces asbestos-containing waste material.

Waste shipment record means the shipping document, required to be originated and signed by the waste generator, used to track and substantiate the disposition of asbestos-containing waste material.

Working day means Monday through Friday and includes holidays that fall on any of the days Monday through Friday.

[49 FR 13661, Apr. 5, 1984; 49 FR 25453, June 21, 1984, as amended by 55 FR 48414, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991; 60 FR 31920, June 19, 1995]

§ 61.142 Standard for asbestos mills.

- (a) Each owner or operator of an asbestos mill shall either discharge no visible emissions to the outside air from that asbestos mill, including fugitive sources, or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
- (b) Each owner or operator of an asbestos mill shall meet the following requirements:
 - (1) Monitor each potential source of asbestos emissions from any part of the mill facility, including air cleaning devices, process equipment, and buildings that house equipment for material processing and handling, at least once each day, during daylight hours, for visible emissions to the outside air during periods of operation. The monitoring shall be by visual observation of at least 15 seconds duration per source of emissions.
 - (2) Inspect each air cleaning device at least once each week for proper operation and for changes that signal the potential for malfunction, including, to the maximum extent possible without dismantling other than opening the device, the presence of tears, holes, and abrasions in filter bags and for dust

deposits on the clean side of bags. For air cleaning devices that cannot be inspected on a weekly basis according to this paragraph, submit to the Administrator, and revise as necessary, a written maintenance plan to include, at a minimum, the following:

- (i) Maintenance schedule.
 - (ii) Recordkeeping plan.
- (3) Maintain records of the results of visible emissions monitoring and air cleaning device inspections using a format similar to that shown in Figures 1 and 2 and include the following:
- (i) Date and time of each inspection.
 - (ii) Presence or absence of visible emissions.
 - (iii) Condition of fabric filters, including presence of any tears, holes, and abrasions.
 - (iv) Presence of dust deposits on clean side of fabric filters.
 - (v) Brief description of corrective actions taken, including date and time.
 - (vi) Daily hours of operation for each air cleaning device.
- (4) Furnish upon request, and make available at the affected facility during normal business hours for inspection by the Administrator, all records required under this section.
- (5) Retain a copy of all monitoring and inspection records for at least 2 years.
- (6) Submit semiannually a copy of visible emission monitoring records to the Administrator if visible emissions occurred during the report period. Semiannual reports shall be postmarked by the 30th day following the end of the six-month period.

Date of inspection (mo/day/yr)	Time of inspection (a.m./p.m.)	Air cleaning device or fugitive source designation or number	Visible emissions observed (yes/no), corrective action taken	Daily operating hours	Inspector's initials

Figure 1. Record of Visible Emission Monitoring

1. Air cleaning device designation or number	_____	_____	_____	_____
2. Date of inspection	_____	_____	_____	_____
3. Time of inspection	_____	_____	_____	_____
4. Is air cleaning device operating properly (yes/no)	_____	_____	_____	_____
5. Tears, holes, or abrasions in fabric filter (yes/no)	_____	_____	_____	_____
6. Dust on clean side of fabric filters (yes/no)	_____	_____	_____	_____
7. Other signs of malfunctions or potential malfunctions (yes/no)	_____	_____	_____	_____
8. Describe other malfunctions or signs of potential malfunctions.	_____ _____ _____			
9. Describe corrective action(s) taken.	_____ _____ _____			
10. Date and time corrective action taken	_____	_____	_____	_____
11. Inspected by	_____			
_____	_____	_____	_____	_____
(Print/Type Name)	(Title)	(Signature)	(Date)	
_____	_____	_____	_____	_____
(Print/Type Name)	(Title)	(Signature)	(Date)	

Figure 2. Air Cleaning Device Inspection Checklist

[55 FR 48416, Nov. 20, 1990, as amended at 64 FR 7467, Feb. 12, 1999]

§ 61.143 Standard for roadways.

No person may construct or maintain a roadway with asbestos tailings or asbestos-containing waste material on that roadway, unless, for asbestos tailings.

- (a) It is a temporary roadway on an area of asbestos ore deposits (asbestos mine): or
- (b) It is a temporary roadway at an active asbestos mill site and is encapsulated with a resinous or bituminous binder. The encapsulated road surface must be maintained at a minimum frequency of once per year to prevent dust emissions; or
- (c) It is encapsulated in asphalt concrete meeting the specifications contained in section 401 of Standard Specifications for Construction of Roads and Bridges on Federal Highway Projects, FP-85, 1985, or their equivalent.

[55 FR 48419, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991]

§ 61.144 Standard for manufacturing.

- (a) **Applicability.** This section applies to the following manufacturing operations using commercial asbestos.
 - (1) The manufacture of cloth, cord, wicks, tubing, tape, twine, rope, thread, yarn, roving, lap, or other textile materials.
 - (2) The manufacture of cement products.
 - (3) The manufacture of fireproofing and insulating materials.
 - (4) The manufacture of friction products.
 - (5) The manufacture of paper, millboard, and felt.
 - (6) The manufacture of floor tile.
 - (7) The manufacture of paints, coatings, caulks, adhesives, and sealants.
 - (8) The manufacture of plastics and rubber materials.
 - (9) The manufacture of chlorine utilizing asbestos diaphragm technology.
 - (10) The manufacture of shotgun shell wads.
 - (11) The manufacture of asphalt concrete.
- (b) **Standard.** Each owner or operator of any of the manufacturing operations to which this section applies shall either:
 - (1) Discharge no visible emissions to the outside air from these operations or from any building or structure in which they are conducted or from any other fugitive sources; or
 - (2) Use the methods specified by § 61.152 to clean emissions from these operations containing particulate asbestos material before they escape to, or are vented to, the outside air.

- (3) Monitor each potential source of asbestos emissions from any part of the manufacturing facility, including air cleaning devices, process equipment, and buildings housing material processing and handling equipment, at least once each day during daylight hours for visible emissions to the outside air during periods of operation. The monitoring shall be by visual observation of at least 15 seconds duration per source of emissions.
- (4) Inspect each air cleaning device at least once each week for proper operation and for changes that signal the potential for malfunctions, including, to the maximum extent possible without dismantling other than opening the device, the presence of tears, holes, and abrasions in filter bags and for dust deposits on the clean side of bags. For air cleaning devices that cannot be inspected on a weekly basis according to this paragraph, submit to the Administrator, and revise as necessary, a written maintenance plan to include, at a minimum, the following:
 - (i) Maintenance schedule.
 - (ii) Recordkeeping plan.
- (5) Maintain records of the results of visible emission monitoring and air cleaning device inspections using a format similar to that shown in Figures 1 and 2 and include the following.
 - (i) Date and time of each inspection.
 - (ii) Presence or absence of visible emissions.
 - (iii) Condition of fabric filters, including presence of any tears, holes and abrasions.
 - (iv) Presence of dust deposits on clean side of fabric filters.
 - (v) Brief description of corrective actions taken, including date and time.
 - (vi) Daily hours of operation for each air cleaning device.
- (6) Furnish upon request, and make available at the affected facility during normal business hours for inspection by the Administrator, all records required under this section.
- (7) Retain a copy of all monitoring and inspection records for at least 2 years.
- (8) Submit semiannually a copy of the visible emission monitoring records to the Administrator if visible emission occurred during the report period. Semiannual reports shall be postmarked by the 30th day following the end of the six-month period.

[49 FR 13661, Apr. 5, 1984, as amended at 55 FR 48419, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991; 64 FR 7467, Feb. 12, 1999]

§ 61.145 Standard for demolition and renovation.

- (a) **Applicability.** To determine which requirements of paragraphs (a), (b), and (c) of this section apply to the owner or operator of a demolition or renovation activity and prior to the commencement of the demolition or renovation, thoroughly inspect the affected facility or part of the facility where the demolition or renovation operation will occur for the presence of asbestos, including Category I and Category II nonfriable ACM. The requirements of paragraphs (b) and (c) of this section apply to each owner or operator of a demolition or renovation activity, including the removal of RACM as follows:
 - (1) In a facility being demolished, all the requirements of paragraphs (b) and (c) of this section apply, except as provided in paragraph (a)(3) of this section, if the combined amount of RACM is

- (i) At least 80 linear meters (260 linear feet) on pipes or at least 15 square meters (160 square feet) on other facility components, or
 - (ii) At least 1 cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously.
- (2) In a facility being demolished, only the notification requirements of paragraphs (b)(1), (2), (3)(i) and (iv), and (4)(i) through (vii) and (4)(ix) and (xvi) of this section apply, if the combined amount of RACM is
 - (i) Less than 80 linear meters (260 linear feet) on pipes and less than 15 square meters (160 square feet) on other facility components, and
 - (ii) Less than one cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously or there is no asbestos.
- (3) If the facility is being demolished under an order of a State or local government agency, issued because the facility is structurally unsound and in danger of imminent collapse, only the requirements of paragraphs (b)(1), (b)(2), (b)(3)(iii), (b)(4) (except (b)(4)(viii)), (b)(5), and (c)(4) through (c)(9) of this section apply.
- (4) In a facility being renovated, including any individual nonscheduled renovation operation, all the requirements of paragraphs (b) and (c) of this section apply if the combined amount of RACM to be stripped, removed, dislodged, cut, drilled, or similarly disturbed is
 - (i) At least 80 linear meters (260 linear feet) on pipes or at least 15 square meters (160 square feet) on other facility components, or
 - (ii) At least 1 cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously.
 - (iii) To determine whether paragraph (a)(4) of this section applies to planned renovation operations involving individual nonscheduled operations, predict the combined additive amount of RACM to be removed or stripped during a calendar year of January 1 through December 31.
 - (iv) To determine whether paragraph (a)(4) of this section applies to emergency renovation operations, estimate the combined amount of RACM to be removed or stripped as a result of the sudden, unexpected event that necessitated the renovation.
- (5) Owners or operators of demolition and renovation operations are exempt from the requirements of §§ 61.05(a), 61.07, and 61.09.
- (b) **Notification requirements.** Each owner or operator of a demolition or renovation activity to which this section applies shall:
 - (1) Provide the Administrator with written notice of intention to demolish or renovate. Delivery of the notice by U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.
 - (2) Update notice, as necessary, including when the amount of asbestos affected changes by at least 20 percent.
 - (3) Postmark or deliver the notice as follows:

- (i) At least 10 working days before asbestos stripping or removal work or any other activity begins (such as site preparation that would break up, dislodge or similarly disturb asbestos material), if the operation is described in paragraphs (a) (1) and (4) (except (a)(4)(iii) and (a)(4)(iv)) of this section. If the operation is as described in paragraph (a)(2) of this section, notification is required 10 working days before demolition begins.
- (ii) At least 10 working days before the end of the calendar year preceding the year for which notice is being given for renovations described in paragraph (a)(4)(iii) of this section.
- (iii) As early as possible before, but not later than, the following working day if the operation is a demolition ordered according to paragraph (a)(3) of this section or, if the operation is a renovation described in paragraph (a)(4)(iv) of this section.
- (iv) For asbestos stripping or removal work in a demolition or renovation operation, described in paragraphs (a) (1) and (4) (except (a)(4)(iii) and (a)(4)(iv)) of this section, and for a demolition described in paragraph (a)(2) of this section, that will begin on a date other than the one contained in the original notice, notice of the new start date must be provided to the Administrator as follows:
 - (A) When the asbestos stripping or removal operation or demolition operation covered by this paragraph will begin after the date contained in the notice,
 - (1) Notify the Administrator of the new start date by telephone as soon as possible before the original start date, and
 - (2) Provide the Administrator with a written notice of the new start date as soon as possible before, and no later than, the original start date. Delivery of the updated notice by the U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.
 - (B) When the asbestos stripping or removal operation or demolition operation covered by this paragraph will begin on a date earlier than the original start date,
 - (1) Provide the Administrator with a written notice of the new start date at least 10 working days before asbestos stripping or removal work begins.
 - (2) For demolitions covered by paragraph (a)(2) of this section, provide the Administrator written notice of a new start date at least 10 working days before commencement of demolition. Delivery of updated notice by U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.
 - (C) In no event shall an operation covered by this paragraph begin on a date other than the date contained in the written notice of the new start date.
- (4) Include the following in the notice:
 - (i) An indication of whether the notice is the original or a revised notification.
 - (ii) Name, address, and telephone number of both the facility owner and operator and the asbestos removal contractor owner or operator.
 - (iii) Type of operation: demolition or renovation.
 - (iv) Description of the facility or affected part of the facility including the size (square meters [square feet] and number of floors), age, and present and prior use of the facility.

- (v) Procedure, including analytical methods, employed to detect the presence of RACM and Category I and Category II nonfriable ACM.
 - (vi) Estimate of the approximate amount of RACM to be removed from the facility in terms of length of pipe in linear meters (linear feet), surface area in square meters (square feet) on other facility components, or volume in cubic meters (cubic feet) if off the facility components. Also, estimate the approximate amount of Category I and Category II nonfriable ACM in the affected part of the facility that will not be removed before demolition.
 - (vii) Location and street address (including building number or name and floor or room number, if appropriate), city, county, and state, of the facility being demolished or renovated.
 - (viii) Scheduled starting and completion dates of asbestos removal work (or any other activity, such as site preparation that would break up, dislodge, or similarly disturb asbestos material) in a demolition or renovation; planned renovation operations involving individual nonscheduled operations shall only include the beginning and ending dates of the report period as described in paragraph (a)(4)(iii) of this section.
 - (ix) Scheduled starting and completion dates of demolition or renovation.
 - (x) Description of planned demolition or renovation work to be performed and method(s) to be employed, including demolition or renovation techniques to be used and description of affected facility components.
 - (xi) Description of work practices and engineering controls to be used to comply with the requirements of this subpart, including asbestos removal and waste-handling emission control procedures.
 - (xii) Name and location of the waste disposal site where the asbestos-containing waste material will be deposited.
 - (xiii) A certification that at least one person trained as required by paragraph (c)(8) of this section will supervise the stripping and removal described by this notification. This requirement shall become effective 1 year after promulgation of this regulation.
 - (xiv) For facilities described in paragraph (a)(3) of this section, the name, title, and authority of the State or local government representative who has ordered the demolition, the date that the order was issued, and the date on which the demolition was ordered to begin. A copy of the order shall be attached to the notification.
 - (xv) For emergency renovations described in paragraph (a)(4)(iv) of this section, the date and hour that the emergency occurred, a description of the sudden, unexpected event, and an explanation of how the event caused an unsafe condition, or would cause equipment damage or an unreasonable financial burden.
 - (xvi) Description of procedures to be followed in the event that unexpected RACM is found or Category II nonfriable ACM becomes crumbled, pulverized, or reduced to powder.
 - (xvii) Name, address, and telephone number of the waste transporter.
- (5) The information required in paragraph (b)(4) of this section must be reported using a form similar to that shown in Figure 3.

- (c) ***Procedures for asbestos emission control.*** Each owner or operator of a demolition or renovation activity to whom this paragraph applies, according to paragraph (a) of this section, shall comply with the following procedures:
- (1) Remove all RACM from a facility being demolished or renovated before any activity begins that would break up, dislodge, or similarly disturb the material or preclude access to the material for subsequent removal. RACM need not be removed before demolition if:
 - (i) It is Category I nonfriable ACM that is not in poor condition and is not friable.
 - (ii) It is on a facility component that is encased in concrete or other similarly hard material and is adequately wet whenever exposed during demolition; or
 - (iii) It was not accessible for testing and was, therefore, not discovered until after demolition began and, as a result of the demolition, the material cannot be safely removed. If not removed for safety reasons, the exposed RACM and any asbestos-contaminated debris must be treated as asbestos-containing waste material and adequately wet at all times until disposed of.
 - (iv) They are Category II nonfriable ACM and the probability is low that the materials will become crumbled, pulverized, or reduced to powder during demolition.
 - (2) When a facility component that contains, is covered with, or is coated with RACM is being taken out of the facility as a unit or in sections:
 - (i) Adequately wet all RACM exposed during cutting or disjoining operations; and
 - (ii) Carefully lower each unit or section to the floor and to ground level, not dropping, throwing, sliding, or otherwise damaging or disturbing the RACM.
 - (3) When RACM is stripped from a facility component while it remains in place in the facility, adequately wet the RACM during the stripping operation.
 - (i) In renovation operations, wetting is not required if:
 - (A) The owner or operator has obtained prior written approval from the Administrator based on a written application that wetting to comply with this paragraph would unavoidably damage equipment or present a safety hazard; and
 - (B) The owner or operator uses of the following emission control methods:
 - (1) A local exhaust ventilation and collection system designed and operated to capture the particulate asbestos material produced by the stripping and removal of the asbestos materials. The system must exhibit no visible emissions to the outside air or be designed and operated in accordance with the requirements in § 61.152.
 - (2) A glove-bag system designed and operated to contain the particulate asbestos material produced by the stripping of the asbestos materials.
 - (3) Leak-tight wrapping to contain all RACM prior to dismantlement.
 - (ii) In renovation operations where wetting would result in equipment damage or a safety hazard, and the methods allowed in paragraph (c)(3)(i) of this section cannot be used, another method may be used after obtaining written approval from the Administrator based upon a determination that it is equivalent to wetting in controlling emissions or to the methods allowed in paragraph (c)(3)(i) of this section.

- (iii) A copy of the Administrator's written approval shall be kept at the worksite and made available for inspection.
- (4) After a facility component covered with, coated with, or containing RACM has been taken out of the facility as a unit or in sections pursuant to paragraph (c)(2) of this section, it shall be stripped or contained in leak-tight wrapping, except as described in paragraph (c)(5) of this section. If stripped, either:
 - (i) Adequately wet the RACM during stripping; or
 - (ii) Use a local exhaust ventilation and collection system designed and operated to capture the particulate asbestos material produced by the stripping. The system must exhibit no visible emissions to the outside air or be designed and operated in accordance with the requirements in § 61.152.
- (5) For large facility components such as reactor vessels, large tanks, and steam generators, but not beams (which must be handled in accordance with paragraphs (c)(2), (3), and (4) of this section), the RACM is not required to be stripped if the following requirements are met:
 - (i) The component is removed, transported, stored, disposed of, or reused without disturbing or damaging the RACM.
 - (ii) The component is encased in a leak-tight wrapping.
 - (iii) The leak-tight wrapping is labeled according to § 61.149(d)(1)(i), (ii), and (iii) during all loading and unloading operations and during storage.
- (6) For all RACM, including material that has been removed or stripped:
 - (i) Adequately wet the material and ensure that it remains wet until collected and contained or treated in preparation for disposal in accordance with § 61.150; and
 - (ii) Carefully lower the material to the ground and floor, not dropping, throwing, sliding, or otherwise damaging or disturbing the material.
 - (iii) Transport the material to the ground via leak-tight chutes or containers if it has been removed or stripped more than 50 feet above ground level and was not removed as units or in sections.
 - (iv) RACM contained in leak-tight wrapping that has been removed in accordance with paragraphs (c)(4) and (c)(3)(i)(B)(3) of this section need not be wetted.
- (7) When the temperature at the point of wetting is below 0 °C (32 °F):
 - (i) The owner or operator need not comply with paragraph (c)(2)(i) and the wetting provisions of paragraph (c)(3) of this section.
 - (ii) The owner or operator shall remove facility components containing, coated with, or covered with RACM as units or in sections to the maximum extent possible.
 - (iii) During periods when wetting operations are suspended due to freezing temperatures, the owner or operator must record the temperature in the area containing the facility components at the beginning, middle, and end of each workday and keep daily temperature records available for inspection by the Administrator during normal business hours at the demolition or renovation site. The owner or operator shall retain the temperature records for at least 2 years.

- (8) Effective 1 year after promulgation of this regulation, no RACM shall be stripped, removed, or otherwise handled or disturbed at a facility regulated by this section unless at least one on-site representative, such as a foreman or management-level person or other authorized representative, trained in the provisions of this regulation and the means of complying with them, is present. Every 2 years, the trained on-site individual shall receive refresher training in the provisions of this regulation. The required training shall include as a minimum: applicability; notifications; material identification; control procedures for removals including, at least, wetting, local exhaust ventilation, negative pressure enclosures, glove-bag procedures, and High Efficiency Particulate Air (HEPA) filters; waste disposal work practices; reporting and recordkeeping; and asbestos hazards and worker protection. Evidence that the required training has been completed shall be posted and made available for inspection by the Administrator at the demolition or renovation site.
- (9) For facilities described in paragraph (a)(3) of this section, adequately wet the portion of the facility that contains RACM during the wrecking operation.
- (10) If a facility is demolished by intentional burning, all RACM including Category I and Category II nonfriable ACM must be removed in accordance with the NESHAP before burning.

NOTIFICATION OF DEMOLITION AND RENOVATION

Operator Project #	Postmark	Date Received	Notification #
I. TYPE OF NOTIFICATION (O=Original R=Revised C=Cancelled):			
II. FACILITY INFORMATION (Identify owner, removal contractor, and other operator)			
OWNER NAME:			
Address:			
City:	State:	Zip:	
Contact:	Tel:		
REMOVAL CONTRACTOR:			
Address:			
City:	State:	Zip:	
Contact:	Tel:		
OTHER OPERATOR:			
Address:			
City:	State:	Zip:	
Contact:	Tel:		
III. TYPE OF OPERATION (D=Demo O=Ordered Demo R=Renovation E=Emer.Renovation):			
IV. IS ASBESTOS PRESENT? (Yes/No)			
V. FACILITY DESCRIPTION (Include building name, number and floor or room number)			
Bldg Name:			
Address:			
City:	State:	County:	
Site Location:			
Building Size:	# of Floors:	Age in Years:	
Present User:		Prior User:	
VI. PROCEDURE, INCLUDING ANALYTICAL METHOD, IF APPROPRIATE, USED TO DETECT THE PRESENCE OF ASBESTOS MATERIAL:			
VII. APPROXIMATE AMOUNT OF ASBESTOS, INCLUDING:		Nonfriable Asbestos Material Not To Be Removed	
1. Regulated ACM to be removed		RACM To Be Removed	Indicate Unit of Measurement Below
2. Category I ACM Not Removed			
3. Category II ACM Not Removed		Cat I	Cat II
Pipes			Ln Ft: Ln m:
Surface Area			Sq Ft: Sq m:
Vol RACM Off Facility Component			Cu Ft: Cu m:
VIII. SCHEDULED DATES ASBESTOS REMOVAL (MM/DD/YY) Start: Complete:			
IX. SCHEDULED DATES DEMO/RENOVATION (MM/DD/YY) Start: Complete:			

Continued on page two

Figure 3. Notification of Demolition and Renovation

NOTIFICATION OF DEMOLITION AND RENOVATION (continued)

X. DESCRIPTION OF PLANNED DEMOLITION OR RENOVATION WORK, AND METHOD(S) TO BE USED:		
XI. DESCRIPTION OF WORK PRACTICES AND ENGINEERING CONTROLS TO BE USED TO PREVENT EMISSIONS OF ASBESTOS AT THE DEMOLITION AND RENOVATION SITE:		
XII. WASTE TRANSPORTER #1		
Name:		
Address:		
City:	State:	Zip:
Contact Person:		Telephone:
WASTE TRANSPORTER #2		
Name:		
Address:		
City:	State:	Zip:
Contact Person:		Telephone:
XIII. WASTE DISPOSAL SITE		
Name:		
Location:		
City:	State:	Zip:
Telephone:		
XIV. IF DEMOLITION ORDERED BY A GOVERNMENT AGENCY, PLEASE IDENTIFY THE AGENCY BELOW:		
Name:	Title:	
Authority:		
Date of Order (MM/DD/YY):	Date Ordered to Begin (MM/DD/YY):	
XV. FOR EMERGENCY RENOVATIONS		
Date and Hour of Emergency (MM/DD/YY):		
Description of the Sudden, Unexpected Event:		
Explanation of how the event caused unsafe conditions or would cause equipment damage or an unreasonable financial burden:		
XVI. DESCRIPTION OF PROCEDURES TO BE FOLLOWED IN THE EVENT THAT UNEXPECTED ASBESTOS IS FOUND OR PREVIOUSLY NONFRIABLE ASBESTOS MATERIAL BECOMES CRUMBLED, PULVERIZED, OR REDUCED TO POWDER.		
XVI. I CERTIFY THAT AN INDIVIDUAL TRAINED IN THE PROVISIONS OF THIS REGULATION (40 CFR PART 61, SUBPART M) WILL BE ON-SITE DURING THE DEMOLITION OR RENOVATION AND EVIDENCE THAT THE REQUIRED TRAINING HAS BEEN ACCOMPLISHED BY THIS PERSON WILL BE AVAILABLE FOR INSPECTION DURING NORMAL BUSINESS HOURS. (Required 1 year after promulgation)		
_____ (Signature of Owner/Operator)		_____ (Date)
XVII. I CERTIFY THAT THE ABOVE INFORMATION IS CORRECT.		
_____ (Signature of Owner/Operator)		_____ (Date)

Figure 3. Notification of Demolition and Renovation

[55 FR 48419, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991]

§ 61.146 Standard for spraying.

The owner or operator of an operation in which asbestos-containing materials are spray applied shall comply with the following requirements:

- (a) For spray-on application on buildings, structures, pipes, and conduits, do not use material containing more than 1 percent asbestos as determined using the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy, except as provided in paragraph (c) of this section.
- (b) For spray-on application of materials that contain more than 1 percent asbestos as determined using the method specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy, on equipment and machinery, except as provided in paragraph (c) of this section:
 - (1) Notify the Administrator at least 20 days before beginning the spraying operation. Include the following information in the notice:
 - (i) Name and address of owner or operator.
 - (ii) Location of spraying operation.
 - (iii) Procedures to be followed to meet the requirements of this paragraph.
 - (2) Discharge no visible emissions to the outside air from spray-on application of the asbestos-containing material or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
- (c) The requirements of paragraphs (a) and (b) of this section do not apply to the spray-on application of materials where the asbestos fibers in the materials are encapsulated with a bituminous or resinous binder during spraying and the materials are not friable after drying.
- (d) Owners or operators of sources subject to this paragraph are exempt from the requirements of §§ 61.05(a), 61.07 and 61.09.

[49 FR 13661, Apr. 5, 1984. Redesignated and amended at 55 FR 48424, Nov. 20, 1990; 60 FR 31920, June 19, 1995]

§ 61.147 Standard for fabricating.

- (a) **Applicability.** This section applies to the following fabricating operations using commercial asbestos:
 - (1) The fabrication of cement building products.
 - (2) The fabrication of friction products, except those operations that primarily install asbestos friction materials on motor vehicles.
 - (3) The fabrication of cement or silicate board for ventilation hoods; ovens; electrical panels; laboratory furniture, bulkheads, partitions, and ceilings for marine construction; and flow control devices for the molten metal industry.
- (b) **Standard.** Each owner or operator of any of the fabricating operations to which this section applies shall either:

- (1) Discharge no visible emissions to the outside air from any of the operations or from any building or structure in which they are conducted or from any other fugitive sources; or
- (2) Use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
- (3) Monitor each potential source of asbestos emissions from any part of the fabricating facility, including air cleaning devices, process equipment, and buildings that house equipment for material processing and handling, at least once each day, during daylight hours, for visible emissions to the outside air during periods of operation. The monitoring shall be by visual observation of at least 15 seconds duration per source of emissions.
- (4) Inspect each air cleaning device at least once each week for proper operation and for changes that signal the potential for malfunctions, including, to the maximum extent possible without dismantling other than opening the device, the presence of tears, holes, and abrasions in filter bags and for dust deposits on the clean side of bags. For air cleaning devices that cannot be inspected on a weekly basis according to this paragraph, submit to the Administrator, and revise as necessary, a written maintenance plan to include, at a minimum, the following:
 - (i) Maintenance schedule.
 - (ii) Recordkeeping plan.
- (5) Maintain records of the results of visible emission monitoring and air cleaning device inspections using a format similar to that shown in Figures 1 and 2 and include the following:
 - (i) Date and time of each inspection.
 - (ii) Presence or absence of visible emissions.
 - (iii) Condition of fabric filters, including presence of any tears, holes, and abrasions.
 - (iv) Presence of dust deposits on clean side of fabric filters.
 - (v) Brief description of corrective actions taken, including date and time.
 - (vi) Daily hours of operation for each air cleaning device.
- (6) Furnish upon request and make available at the affected facility during normal business hours for inspection by the Administrator, all records required under this section.
- (7) Retain a copy of all monitoring and inspection records for at least 2 years.
- (8) Submit semiannually a copy of the visible emission monitoring records to the Administrator if visible emission occurred during the report period. Semiannual reports shall be postmarked by the 30th day following the end of the six-month period.

[49 FR 13661, Apr. 5, 1984. Redesignated and amended at 55 FR 48424, Nov. 20, 1991; 64 FR 7467, Feb. 12, 1999]

§ 61.148 Standard for insulating materials.

No owner or operator of a facility may install or reinstall on a facility component any insulating materials that contain commercial asbestos if the materials are either molded and friable or wet-applied and friable after drying. The provisions of this section do not apply to spray-applied insulating materials regulated under § 61.146.

[55 FR 48424, Nov. 20, 1990]

§ 61.149 Standard for waste disposal for asbestos mills.

Each owner or operator of any source covered under the provisions of § 61.142 shall:

- (a) Deposit all asbestos-containing waste material at a waste disposal site operated in accordance with the provisions of § 61.154; and
- (b) Discharge no visible emissions to the outside air from the transfer of control device asbestos waste to the tailings conveyor, or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air. Dispose of the asbestos waste from control devices in accordance with § 61.150(a) or paragraph (c) of this section; and
- (c) Discharge no visible emissions to the outside air during the collection, processing, packaging, or on-site transporting of any asbestos-containing waste material, or use one of the disposal methods specified in paragraphs (c) (1) or (2) of this section, as follows:
 - (1) Use a wetting agent as follows:
 - (i) Adequately mix all asbestos-containing waste material with a wetting agent recommended by the manufacturer of the agent to effectively wet dust and tailings, before depositing the material at a waste disposal site. Use the agent as recommended for the particular dust by the manufacturer of the agent.
 - (ii) Discharge no visible emissions to the outside air from the wetting operation or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
 - (iii) Wetting may be suspended when the ambient temperature at the waste disposal site is less than -9.5°C (15°F), as determined by an appropriate measurement method with an accuracy of $\pm 1^{\circ}\text{C}$ ($\pm 2^{\circ}\text{F}$). During periods when wetting operations are suspended, the temperature must be recorded at least at hourly intervals, and records must be retained for at least 2 years in a form suitable for inspection.
 - (2) Use an alternative emission control and waste treatment method that has received prior written approval by the Administrator. To obtain approval for an alternative method, a written application must be submitted to the Administrator demonstrating that the following criteria are met:
 - (i) The alternative method will control asbestos emissions equivalent to currently required methods.
 - (ii) The suitability of the alternative method for the intended application.
 - (iii) The alternative method will not violate other regulations.
 - (iv) The alternative method will not result in increased water pollution, land pollution, or occupational hazards.
- (d) When waste is transported by vehicle to a disposal site:
 - (1) Mark vehicles used to transport asbestos-containing waste material during the loading and unloading of the waste so that the signs are visible. The markings must:
 - (i) Be displayed in such a manner and location that a person can easily read the legend.

- (ii) Conform to the requirements for 51 cm × 36 cm (20 in × 14 in) upright format signs specified in 29 CFR 1910.145(d)(4) and this paragraph; and
- (iii) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

LEGEND

DANGER

ASBESTOS DUST HAZARD

CANCER AND LUNG DISEASE HAZARD

AUTHORIZED PERSONNEL ONLY

NOTATION

2.5 CM (1 INCH) SANS SERIF, GOTHIC OR BLOCK

2.5 CM (1 INCH) SANS SERIF, GOTHIC OR BLOCK

1.9 CM (3/4 INCH) SANS SERIF, GOTHIC OR BLOCK

14 POINT GOTHIC

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

- (2) For off-site disposal, provide a copy of the waste shipment record, described in paragraph (e)(1) of this section, to the disposal site owner or operator at the same time as the asbestos-containing waste material is delivered to the disposal site.
- (e) For all asbestos-containing waste material transported off the facility site:
 - (1) Maintain asbestos waste shipment records, using a form similar to that shown in Figure 4, and include the following information:
 - (i) The name, address, and telephone number of the waste generator.
 - (ii) The name and address of the local, State, or EPA Regional agency responsible for administering the asbestos NESHAP program.
 - (iii) The quantity of the asbestos-containing waste material in cubic meters (cubic yards).
 - (iv) The name and telephone number of the disposal site operator.
 - (v) The name and physical site location of the disposal site.
 - (vi) The date transported.
 - (vii) The name, address, and telephone number of the transporter(s).

- (viii) A certification that the contents of this consignment are fully and accurately described by proper shipping name and are classified, packed, marked, and labeled, and are in all respects in proper condition for transport by highway according to applicable international and government regulations.
- (2) For waste shipments where a copy of the waste shipment record, signed by the owner or operator of the designated disposal site, is not received by the waste generator within 35 days of the date the waste was accepted by the initial transporter, contact the transporter and/or the owner or operator of the designated disposal site to determine the status of the waste shipment.
- (3) Report in writing to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator if a copy of the waste shipment record, signed by the owner or operator of the designated waste disposal site, is not received by the waste generator within 45 days of the date the waste was accepted by the initial transporter. Include in the report the following information:
 - (i) A copy of the waste shipment record for which a confirmation of delivery was not received, and
 - (ii) A cover letter signed by the waste generator explaining the efforts taken to locate the asbestos waste shipment and the results of those efforts.
- (4) Retain a copy of all waste shipment records, including a copy of the waste shipment record signed by the owner or operator of the designated waste disposal site, for at least 2 years.
- (f) Furnish upon request, and make available for inspection by the Administrator, all records required under this section.

Generator	1. Work site name and mailing address		Owner's name	Owner's telephone no.
	2. Operator's name and address			Operator's telephone no.
	3. Waste disposal site (WDS) name, mailing address, and physical site location			WDS phone no.
	4. Name, and address of responsible agency			
	5. Description of materials		6. Containers No. Type	7. Total quantity m ³ (yd ³)
Transporter	8. Special handling instructions and additional information			
	9. OPERATOR'S CERTIFICATION: I hereby declare that the contents of this consignment are fully and accurately described above by proper shipping name and are classified, packed, marked, and labeled, and are in all respects in proper condition for transport by highway according to applicable international and government regulations.			
	Printed/typed name & title		Signature	Month Day Year
	10. Transporter 1 (Acknowledgment of receipt of materials)			
	Printed/typed name & title		Signature	Month Day Year
Disposal Site	Address and telephone no.			
	11. Transporter 2 (Acknowledgment of receipt of materials)			
	Printed/typed name & title		Signature	Month Day Year
	Address and telephone no.			
	12. Discrepancy indication space			
Disposal Site	13. Waste disposal site owner or operator: Certification of receipt of asbestos materials covered by this manifest except as noted in item 12.			
	Printed/typed name & title		Signature	Month Day Year

(Continued)

Figure 4. Waste Shipment Record

INSTRUCTIONS

Waste Generator Section (Items 1-9)

1. Enter the name of the facility at which asbestos waste is generated and the address where the facility is located. In the appropriate spaces, also enter the name of the owner of the facility and the owner's phone number.
2. If a demolition or renovation, enter the name and address of the company and authorized agent responsible for performing the asbestos removal. In the appropriate spaces, also enter the phone number of the operator.
3. Enter the name, address, and physical site location of the waste disposal site (WDS) that will be receiving the asbestos materials. In the appropriate spaces, also enter the phone number of the WDS. Enter "on-site" if the waste will be disposed of on the generator's property.
4. Provide the name and address of the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program.
5. Indicate the types of asbestos waste materials generated. If from a demolition or renovation, indicate the amount of asbestos that is
 - Friable asbestos material
 - Nonfriable asbestos material
6. Enter the number of containers used to transport the asbestos materials listed in item 5. Also enter one of the following container codes used in transporting each type of asbestos material (specify any other type of container used if not listed below):
 - DM - Metal drums, barrels
 - DP - Plastic drums, barrels
 - BA - 6 mil plastic bags or wrapping
7. Enter the quantities of each type of asbestos material removed in units of cubic meters (cubic yards).
8. Use this space to indicate special transportation, treatment, storage or disposal or Bill of Lading information. If an alternate waste disposal site is designated, note it here. Emergency response telephone numbers or similar information may be included here.
9. The authorized agent of the waste generator must read and then sign and date this certification. The date is the date of receipt by transporter.

NOTE: The waste generator must retain a copy of this form.

(continued)

Transporter Section (Items 10 & 11)

10. & 11. Enter name, address, and telephone number of each transporter used, if applicable. Print or type the full name and title of person accepting responsibility and acknowledging receipt of materials as listed on this waste shipment record for transport. Enter date of receipt and signature.

NOTE: The transporter must retain a copy of this form.

Disposal Site Section (Items 12 & 13)

12. The authorized representative of the WDS must note in this space any discrepancy between waste described on this manifest and waste actually received as well as any improperly enclosed or contained waste. Any rejected materials should be listed and destination of those materials provided. A site that converts asbestos-containing waste material to nonasbestos material is considered a WDS.
13. The signature (by hand) of the authorized WDS agent indicates acceptance and agreement with statements on this manifest except as noted in item 12. The date is the date of signature and receipt of shipment.

NOTE: The WDS must retain a completed copy of this form. The WDS must also send a completed copy to the operator listed in item 2.

Figure 4. Waste Shipment Record

§ 61.150 Standard for waste disposal for manufacturing, fabricating, demolition, renovation, and spraying operations.

Each owner or operator of any source covered under the provisions of §§ 61.144, 61.145, 61.146, and 61.147 shall comply with the following provisions:

- (a) Discharge no visible emissions to the outside air during the collection, processing (including incineration), packaging, or transporting of any asbestos-containing waste material generated by the source, or use one of the emission control and waste treatment methods specified in paragraphs (a) (1) through (4) of this section.
 - (1) Adequately wet asbestos-containing waste material as follows:
 - (i) Mix control device asbestos waste to form a slurry; adequately wet other asbestos-containing waste material; and
 - (ii) Discharge no visible emissions to the outside air from collection, mixing, wetting, and handling operations, or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air; and

- (iii) After wetting, seal all asbestos-containing waste material in leak-tight containers while wet; or, for materials that will not fit into containers without additional breaking, put materials into leak-tight wrapping; and
 - (iv) Label the containers or wrapped materials specified in paragraph (a)(1)(iii) of this section using warning labels specified by Occupational Safety and Health Standards of the Department of Labor, Occupational Safety and Health Administration (OSHA) under 29 CFR 1910.1001(j)(4) or 1926.1101(k)(8). The labels shall be printed in letters of sufficient size and contrast so as to be readily visible and legible.
 - (v) For asbestos-containing waste material to be transported off the facility site, label containers or wrapped materials with the name of the waste generator and the location at which the waste was generated.
- (2) Process asbestos-containing waste material into nonfriable forms as follows:
- (i) Form all asbestos-containing waste material into nonfriable pellets or other shapes;
 - (ii) Discharge no visible emissions to the outside air from collection and processing operations, including incineration, or use the method specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
- (3) For facilities demolished where the RACM is not removed prior to demolition according to §§ 61.145(c)(1) (i), (ii), (iii), and (iv) or for facilities demolished according to § 61.145(c)(9), adequately wet asbestos-containing waste material at all times after demolition and keep wet during handling and loading for transport to a disposal site. Asbestos-containing waste materials covered by this paragraph do not have to be sealed in leak-tight containers or wrapping but may be transported and disposed of in bulk.
- (4) Use an alternative emission control and waste treatment method that has received prior approval by the Administrator according to the procedure described in § 61.149(c)(2).
- (5) As applied to demolition and renovation, the requirements of paragraph (a) of this section do not apply to Category I nonfriable ACM waste and Category II nonfriable ACM waste that did not become crumbled, pulverized, or reduced to powder.
- (b) All asbestos-containing waste material shall be deposited as soon as is practical by the waste generator at:
- (1) A waste disposal site operated in accordance with the provisions of § 61.154, or
 - (2) An EPA-approved site that converts RACM and asbestos-containing waste material into nonasbestos (asbestos-free) material according to the provisions of § 61.155.
 - (3) The requirements of paragraph (b) of this section do not apply to Category I nonfriable ACM that is not RACM.
- (c) Mark vehicles used to transport asbestos-containing waste material during the loading and unloading of waste so that the signs are visible. The markings must conform to the requirements of §§ 61.149(d)(1) (i), (ii), and (iii).
- (d) For all asbestos-containing waste material transported off the facility site:
- (1) Maintain waste shipment records, using a form similar to that shown in Figure 4, and include the following information:

- (i) The name, address, and telephone number of the waste generator.
 - (ii) The name and address of the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program.
 - (iii) The approximate quantity in cubic meters (cubic yards).
 - (iv) The name and telephone number of the disposal site operator.
 - (v) The name and physical site location of the disposal site.
 - (vi) The date transported.
 - (vii) The name, address, and telephone number of the transporter(s).
 - (viii) A certification that the contents of this consignment are fully and accurately described by proper shipping name and are classified, packed, marked, and labeled, and are in all respects in proper condition for transport by highway according to applicable international and government regulations.
- (2) Provide a copy of the waste shipment record, described in paragraph (d)(1) of this section, to the disposal site owners or operators at the same time as the asbestos-containing waste material is delivered to the disposal site.
 - (3) For waste shipments where a copy of the waste shipment record, signed by the owner or operator of the designated disposal site, is not received by the waste generator within 35 days of the date the waste was accepted by the initial transporter, contact the transporter and/or the owner or operator of the designated disposal site to determine the status of the waste shipment.
 - (4) Report in writing to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator if a copy of the waste shipment record, signed by the owner or operator of the designated waste disposal site, is not received by the waste generator within 45 days of the date the waste was accepted by the initial transporter. Include in the report the following information:
 - (i) A copy of the waste shipment record for which a confirmation of delivery was not received, and
 - (ii) A cover letter signed by the waste generator explaining the efforts taken to locate the asbestos waste shipment and the results of those efforts.
 - (5) Retain a copy of all waste shipment records, including a copy of the waste shipment record signed by the owner or operator of the designated waste disposal site, for at least 2 years.
- (e) Furnish upon request, and make available for inspection by the Administrator, all records required under this section.

[55 FR 48429, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991, as amended at 68 FR 54793, Sept. 18, 2003]

§ 61.151 Standard for inactive waste disposal sites for asbestos mills and manufacturing and fabricating operations.

Each owner or operator of any inactive waste disposal site that was operated by sources covered under § 61.142, 61.144, or 61.147 and received deposits of asbestos-containing waste material generated by the sources, shall:

- (a) Comply with one of the following:
- (1) Either discharge no visible emissions to the outside air from an inactive waste disposal site subject to this paragraph; or
 - (2) Cover the asbestos-containing waste material with at least 15 centimeters (6 inches) of compacted nonasbestos-containing material, and grow and maintain a cover of vegetation on the area adequate to prevent exposure of the asbestos-containing waste material. In desert areas where vegetation would be difficult to maintain, at least 8 additional centimeters (3 inches) of well-graded, nonasbestos crushed rock may be placed on top of the final cover instead of vegetation and maintained to prevent emissions; or
 - (3) Cover the asbestos-containing waste material with at least 60 centimeters (2 feet) of compacted nonasbestos-containing material, and maintain it to prevent exposure of the asbestos-containing waste; or
 - (4) For inactive waste disposal sites for asbestos tailings, a resinous or petroleum-based dust suppression agent that effectively binds dust to control surface air emissions may be used instead of the methods in paragraphs (a) (1), (2), and (3) of this section. Use the agent in the manner and frequency recommended for the particular asbestos tailings by the manufacturer of the dust suppression agent to achieve and maintain dust control. Obtain prior written approval of the Administrator to use other equally effective dust suppression agents. For purposes of this paragraph, any used, spent, or other waste oil is not considered a dust suppression agent.
- (b) Unless a natural barrier adequately deters access by the general public, install and maintain warning signs and fencing as follows, or comply with paragraph (a)(2) or (a)(3) of this section.
- (1) Display warning signs at all entrances and at intervals of 100 m (328 ft) or less along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material was deposited. The warning signs must:
 - (i) Be posted in such a manner and location that a person can easily read the legend; and
 - (ii) Conform to the requirements for 51 cm × 36 cm (20" × 14") upright format signs specified in 29 CFR 1910.145(d)(4) and this paragraph; and
 - (iii) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

Legend	Notation
Asbestos Waste Disposal Site	2.5 cm (1 inch) Sans Serif, Gothic or Block
Do Not Create Dust	1.9 cm (³ / ₄ inch) Sans Serif, Gothic or Block
Breathing Asbestos is Hazardous to Your Health	14 Point Gothic.

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

- (2) Fence the perimeter of the site in a manner adequate to deter access by the general public.

- (3) When requesting a determination on whether a natural barrier adequately deters public access, supply information enabling the Administrator to determine whether a fence or a natural barrier adequately deters access by the general public.
- (c) The owner or operator may use an alternative control method that has received prior approval of the Administrator rather than comply with the requirements of paragraph (a) or (b) of this section.
- (d) Notify the Administrator in writing at least 45 days prior to excavating or otherwise disturbing any asbestos-containing waste material that has been deposited at a waste disposal site under this section, and follow the procedures specified in the notification. If the excavation will begin on a date other than the one contained in the original notice, notice of the new start date must be provided to the Administrator at least 10 working days before excavation begins and in no event shall excavation begin earlier than the date specified in the original notification. Include the following information in the notice:
 - (1) Scheduled starting and completion dates.
 - (2) Reason for disturbing the waste.
 - (3) Procedures to be used to control emissions during the excavation, storage, transport, and ultimate disposal of the excavated asbestos-containing waste material. If deemed necessary, the Administrator may require changes in the emission control procedures to be used.
 - (4) Location of any temporary storage site and the final disposal site.
- (e) Within 60 days of a site becoming inactive and after the effective date of this subpart, record, in accordance with State law, a notation on the deed to the facility property and on any other instrument that would normally be examined during a title search; this notation will in perpetuity notify any potential purchaser of the property that:
 - (1) The land has been used for the disposal of asbestos-containing waste material;
 - (2) The survey plot and record of the location and quantity of asbestos-containing waste disposed of within the disposal site required in § 61.154(f) have been filed with the Administrator; and
 - (3) The site is subject to 40 CFR part 61, subpart M.

[49 FR 13661, Apr. 5, 1984, as amended at 53 FR 36972, Sept. 23, 1988. Redesignated and amended at 55 FR 48429, Nov. 20, 1990]

§ 61.152 Air-cleaning.

- (a) The owner or operator who uses air cleaning, as specified in §§ 61.142(a), 61.144(b)(2), 61.145(c)(3)(i)(B)(1), 61.145(c)(4)(ii), 61.145(c)(11)(i), 61.146(b)(2), 61.147(b)(2), 61.149(b), 61.149(c)(1)(ii), 61.150(a)(1)(ii), 61.150(a)(2)(ii), and 61.155(e) shall:
 - (1) Use fabric filter collection devices, except as noted in paragraph (b) of this section, doing all of the following:
 - (i) Ensuring that the airflow permeability, as determined by ASTM Method D737-75, does not exceed $9 \text{ m}^3/\text{min}/\text{m}^2$ ($30 \text{ ft}^3/\text{min}/\text{ft}^2$) for woven fabrics or $11^3/\text{min}/\text{m}^2$ ($35 \text{ ft}^3/\text{min}/\text{ft}^2$) for felted fabrics, except that $12 \text{ m}^3/\text{min}/\text{m}^2$ ($40 \text{ ft}^3/\text{min}/\text{ft}^2$) for woven and $14 \text{ m}^3/\text{min}/\text{m}^2$ ($45 \text{ ft}^3/\text{min}/\text{ft}^2$) for felted fabrics is allowed for filtering air from asbestos ore dryers; and

- (ii) Ensuring that felted fabric weighs at least 475 grams per square meter (14 ounces per square yard) and is at least 1.6 millimeters (one-sixteenth inch) thick throughout; and
 - (iii) Avoiding the use of synthetic fabrics that contain fill yarn other than that which is spun.
- (2) Properly install, use, operate, and maintain all air-cleaning equipment authorized by this section. Bypass devices may be used only during upset or emergency conditions and then only for so long as it takes to shut down the operation generating the particulate asbestos material.
 - (3) For fabric filter collection devices installed after January 10, 1989, provide for easy inspection for faulty bags.
- (b) There are the following exceptions to paragraph (a)(1):
- (1) After January 10, 1989, if the use of fabric creates a fire or explosion hazard, or the Administrator determines that a fabric filter is not feasible, the Administrator may authorize as a substitute the use of wet collectors designed to operate with a unit contacting energy of at least 9.95 kilopascals (40 inches water gage pressure).
 - (2) Use a HEPA filter that is certified to be at least 99.97 percent efficient for 0.3 micron particles.
 - (3) The Administrator may authorize the use of filtering equipment other than described in paragraphs (a)(1) and (b)(1) and (2) of this section if the owner or operator demonstrates to the Administrator's satisfaction that it is equivalent to the described equipment in filtering particulate asbestos material.

[49 FR 13661, Apr. 5, 1984; 49 FR 25453, June 21, 1984, as amended at 51 FR 8199, Mar. 10, 1986. Redesignated and amended at 55 FR 48430, Nov. 20, 1990]

§ 61.153 Reporting.

- (a) Any new source to which this subpart applies (with the exception of sources subject to §§ 61.143, 61.145, 61.146, and 61.148), which has an initial startup date preceding the effective date of this revision, shall provide the following information to the Administrator postmarked or delivered within 90 days of the effective date. In the case of a new source that does not have an initial startup date preceding the effective date, the information shall be provided, postmarked or delivered, within 90 days of the initial startup date. Any owner or operator of an existing source shall provide the following information to the Administrator within 90 days of the effective date of this subpart unless the owner or operator of the existing source has previously provided this information to the Administrator. Any changes in the information provided by any existing source shall be provided to the Administrator, postmarked or delivered, within 30 days after the change.
- (1) A description of the emission control equipment used for each process; and
 - (i) If the fabric device uses a woven fabric, the airflow permeability in $\text{m}^3/\text{min}/\text{m}^2$ and; if the fabric is synthetic, whether the fill yarn is spun or not spun; and
 - (ii) If the fabric filter device uses a felted fabric, the density in g/m^2 , the minimum thickness in inches, and the airflow permeability in $\text{m}^3/\text{min}/\text{m}^2$.
 - (2) If a fabric filter device is used to control emissions,
 - (i) The airflow permeability in $\text{m}^3/\text{min}/\text{m}^2$ ($\text{ft}^3/\text{min}/\text{ft}^2$) if the fabric filter device uses a woven fabric, and, if the fabric is synthetic, whether the fill yarn is spun or not spun; and

- (ii) If the fabric filter device uses a felted fabric, the density in g/m^2 (oz/yd^2), the minimum thickness in millimeters (inches), and the airflow permeability in $\text{m}^3/\text{min}/\text{m}^2$ ($\text{ft}^3/\text{min}/\text{ft}^2$).
- (3) If a HEPA filter is used to control emissions, the certified efficiency.
- (4) For sources subject to §§ 61.149 and 61.150:
 - (i) A brief description of each process that generates asbestos-containing waste material; and
 - (ii) The average volume of asbestos-containing waste material disposed of, measured in m^3/day (yd^3/day); and
 - (iii) The emission control methods used in all stages of waste disposal; and
 - (iv) The type of disposal site or incineration site used for ultimate disposal, the name of the site operator, and the name and location of the disposal site.
- (5) For sources subject to §§ 61.151 and 61.154:
 - (i) A brief description of the site; and
 - (ii) The method or methods used to comply with the standard, or alternative procedures to be used.
- (b) The information required by paragraph (a) of this section must accompany the information required by § 61.10. Active waste disposal sites subject to § 61.154 shall also comply with this provision. Roadways, demolition and renovation, spraying, and insulating materials are exempted from the requirements of § 61.10(a). The information described in this section must be reported using the format of appendix A of this part as a guide.

(Sec. 114. Clean Air Act as amended (42 U.S.C. 7414))

[49 FR 13661, Apr. 5, 1984. Redesignated and amended at 55 FR 48430, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991]

§ 61.154 Standard for active waste disposal sites.

Each owner or operator of an active waste disposal site that receives asbestos-containing waste material from a source covered under § 61.149, 61.150, or 61.155 shall meet the requirements of this section:

- (a) Either there must be no visible emissions to the outside air from any active waste disposal site where asbestos-containing waste material has been deposited, or the requirements of paragraph (c) or (d) of this section must be met.
- (b) Unless a natural barrier adequately deters access by the general public, either warning signs and fencing must be installed and maintained as follows, or the requirements of paragraph (c)(1) of this section must be met.
 - (1) Warning signs must be displayed at all entrances and at intervals of 100 m (330 ft) or less along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material is deposited. The warning signs must:
 - (i) Be posted in such a manner and location that a person can easily read the legend; and
 - (ii) Conform to the requirements of 51 cm × 36 cm (20" × 14") upright format signs specified in 29 CFR 1910.145(d)(4) and this paragraph; and

- (iii) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

Legend	Notation
Asbestos Waste Disposal Site	2.5 cm (1 inch) Sans Serif, Gothic or Block.
Do Not Create Dust	1.9 cm (³ / ₄ inch) Sans Serif, Gothic or Block.
Breathing Asbestos is Hazardous to Your Health	14 Point Gothic.

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

- (2) The perimeter of the disposal site must be fenced in a manner adequate to deter access by the general public.
- (3) Upon request and supply of appropriate information, the Administrator will determine whether a fence or a natural barrier adequately deters access by the general public.
- (c) Rather than meet the no visible emission requirement of paragraph (a) of this section, at the end of each operating day, or at least once every 24-hour period while the site is in continuous operation, the asbestos-containing waste material that has been deposited at the site during the operating day or previous 24-hour period shall:
- (1) Be covered with at least 15 centimeters (6 inches) of compacted nonasbestos-containing material, or
- (2) Be covered with a resinous or petroleum-based dust suppression agent that effectively binds dust and controls wind erosion. Such an agent shall be used in the manner and frequency recommended for the particular dust by the dust suppression agent manufacturer to achieve and maintain dust control. Other equally effective dust suppression agents may be used upon prior approval by the Administrator. For purposes of this paragraph, any used, spent, or other waste oil is not considered a dust suppression agent.
- (d) Rather than meet the no visible emission requirement of paragraph (a) of this section, use an alternative emissions control method that has received prior written approval by the Administrator according to the procedures described in § 61.149(c)(2).
- (e) For all asbestos-containing waste material received, the owner or operator of the active waste disposal site shall:
- (1) Maintain waste shipment records, using a form similar to that shown in Figure 4, and include the following information:
- (i) The name, address, and telephone number of the waste generator.
- (ii) The name, address, and telephone number of the transporter(s).
- (iii) The quantity of the asbestos-containing waste material in cubic meters (cubic yards).

(iv) The presence of improperly enclosed or uncovered waste, or any asbestos-containing waste material not sealed in leak-tight containers. Report in writing to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator (identified in the waste shipment record), and, if different, the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the disposal site, by the following working day, the presence of a significant amount of improperly enclosed or uncovered waste. Submit a copy of the waste shipment record along with the report.

(v) The date of the receipt.

(2) As soon as possible and no longer than 30 days after receipt of the waste, send a copy of the signed waste shipment record to the waste generator.

(3) Upon discovering a discrepancy between the quantity of waste designated on the waste shipment records and the quantity actually received, attempt to reconcile the discrepancy with the waste generator. If the discrepancy is not resolved within 15 days after receiving the waste, immediately report in writing to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator (identified in the waste shipment record), and, if different, the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the disposal site. Describe the discrepancy and attempts to reconcile it, and submit a copy of the waste shipment record along with the report.

(4) Retain a copy of all records and reports required by this paragraph for at least 2 years.

(f) Maintain, until closure, records of the location, depth and area, and quantity in cubic meters (cubic yards) of asbestos-containing waste material within the disposal site on a map or diagram of the disposal area.

(g) Upon closure, comply with all the provisions of § 61.151.

(h) Submit to the Administrator, upon closure of the facility, a copy of records of asbestos waste disposal locations and quantities.

(i) Furnish upon request, and make available during normal business hours for inspection by the Administrator, all records required under this section.

(j) Notify the Administrator in writing at least 45 days prior to excavating or otherwise disturbing any asbestos-containing waste material that has been deposited at a waste disposal site and is covered. If the excavation will begin on a date other than the one contained in the original notice, notice of the new start date must be provided to the Administrator at least 10 working days before excavation begins and in no event shall excavation begin earlier than the date specified in the original notification. Include the following information in the notice:

(1) Scheduled starting and completion dates.

(2) Reason for disturbing the waste.

(3) Procedures to be used to control emissions during the excavation, storage, transport, and ultimate disposal of the excavated asbestos-containing waste material. If deemed necessary, the Administrator may require changes in the emission control procedures to be used.

(4) Location of any temporary storage site and the final disposal site.

(Secs. 112 and 301(a) of the Clean Air Act as amended (42 U.S.C. 7412, 7601(a))

[49 FR 13661, Apr. 5, 1990. Redesignated and amended at 55 FR 48431, Nov. 20, 1990; 56 FR 1669, Jan. 16, 1991]

§ 61.155 Standard for operations that convert asbestos-containing waste material into nonasbestos (asbestos-free) material.

Each owner or operator of an operation that converts RACM and asbestos-containing waste material into nonasbestos (asbestos-free) material shall:

- (a) Obtain the prior written approval of the Administrator to construct the facility. To obtain approval, the owner or operator shall provide the Administrator with the following information:
 - (1) Application to construct pursuant to § 61.07.
 - (2) In addition to the information requirements of § 61.07(b)(3), a
 - (i) Description of waste feed handling and temporary storage.
 - (ii) Description of process operating conditions.
 - (iii) Description of the handling and temporary storage of the end product.
 - (iv) Description of the protocol to be followed when analyzing output materials by transmission electron microscopy.
 - (3) Performance test protocol, including provisions for obtaining information required under paragraph (b) of this section.
 - (4) The Administrator may require that a demonstration of the process be performed prior to approval of the application to construct.
- (b) Conduct a start-up performance test. Test results shall include:
 - (1) A detailed description of the types and quantities of nonasbestos material, RACM, and asbestos-containing waste material processed, e.g., asbestos cement products, friable asbestos insulation, plaster, wood, plastic, wire, etc. Test feed is to include the full range of materials that will be encountered in actual operation of the process.
 - (2) Results of analyses, using polarized light microscopy, that document the asbestos content of the wastes processed.
 - (3) Results of analyses, using transmission electron microscopy, that document that the output materials are free of asbestos. Samples for analysis are to be collected as 8-hour composite samples (one 200-gram (7-ounce) sample per hour), beginning with the initial introduction of RACM or asbestos-containing waste material and continuing until the end of the performance test.
 - (4) A description of operating parameters, such as temperature and residence time, defining the full range over which the process is expected to operate to produce nonasbestos (asbestos-free) materials. Specify the limits for each operating parameter within which the process will produce nonasbestos (asbestos-free) materials.
 - (5) The length of the test.
- (c) During the initial 90 days of operation,

- (1) Continuously monitor and log the operating parameters identified during start-up performance tests that are intended to ensure the production of nonasbestos (asbestos-free) output material.
 - (2) Monitor input materials to ensure that they are consistent with the test feed materials described during start-up performance tests in paragraph (b)(1) of this section.
 - (3) Collect and analyze samples, taken as 10-day composite samples (one 200-gram (7-ounce) sample collected every 8 hours of operation) of all output material for the presence of asbestos. Composite samples may be for fewer than 10 days. Transmission electron microscopy (TEM) shall be used to analyze the output material for the presence of asbestos. During the initial 90-day period, all output materials must be stored on-site until analysis shows the material to be asbestos-free or disposed of as asbestos-containing waste material according to § 61.150.
- (d) After the initial 90 days of operation,
- (1) Continuously monitor and record the operating parameters identified during start-up performance testing and any subsequent performance testing. Any output produced during a period of deviation from the range of operating conditions established to ensure the production of nonasbestos (asbestos-free) output materials shall be:
 - (i) Disposed of as asbestos-containing waste material according to § 61.150, or
 - (ii) Recycled as waste feed during process operation within the established range of operating conditions, or
 - (iii) Stored temporarily on-site in a leak-tight container until analyzed for asbestos content. Any product material that is not asbestos-free shall be either disposed of as asbestos-containing waste material or recycled as waste feed to the process.
 - (2) Collect and analyze monthly composite samples (one 200-gram (7-ounce) sample collected every 8 hours of operation) of the output material. Transmission electron microscopy shall be used to analyze the output material for the presence of asbestos.
- (e) Discharge no visible emissions to the outside air from any part of the operation, or use the methods specified by § 61.152 to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.
- (f) Maintain records on-site and include the following information:
- (1) Results of start-up performance testing and all subsequent performance testing, including operating parameters, feed characteristic, and analyses of output materials.
 - (2) Results of the composite analyses required during the initial 90 days of operation under § 61.155(c).
 - (3) Results of the monthly composite analyses required under § 61.155(d).
 - (4) Results of continuous monitoring and logs of process operating parameters required under § 61.155(c) and (d).
 - (5) The information on waste shipments received as required in § 61.154(e).
 - (6) For output materials where no analyses were performed to determine the presence of asbestos, record the name and location of the purchaser or disposal site to which the output materials were sold or deposited, and the date of sale or disposal.
 - (7) Retain records required by paragraph (f) of this section for at least 2 years.

- (g) Submit the following reports to the Administrator:
- (1) A report for each analysis of product composite samples performed during the initial 90 days of operation.

(2) A quarterly report, including the following information concerning activities during each consecutive 3-month period:

(i) Results of analyses of monthly product composite samples.

(ii) A description of any deviation from the operating parameters established during performance testing, the duration of the deviation, and steps taken to correct the deviation.

(iii) Disposition of any product produced during a period of deviation, including whether it was recycled, disposed of as asbestos-containing waste material, or stored temporarily on-site until analyzed for asbestos content.

(iv) The information on waste disposal activities as required in § 61.154(f).

(h) Nonasbestos (asbestos-free) output material is not subject to any of the provisions of this subpart. Output materials in which asbestos is detected, or output materials produced when the operating parameters deviated from those established during the start-up performance testing, unless shown by TEM analysis to be asbestos-free, shall be considered to be asbestos-containing waste and shall be handled and disposed of according to §§ 61.150 and 61.154 or reprocessed while all of the established operating parameters are being met.
- [55 FR 48431, Nov. 20, 1990]
- § 61.156 Cross-reference to other asbestos regulations.
- In addition to this subpart, the regulations referenced in Table 1 also apply to asbestos and may be applicable to those sources specified in §§ 61.142 through 61.151, 61.154, and 61.155 of this subpart. These cross-references are presented for the reader's information and to promote compliance with the cited regulations.
- TABLE 1—CROSS-REFERENCE TO OTHER ASBESTOS REGULATIONS
- | Agency | CFR citation | Comment |
|--------|----------------------------|--|
| EPA | 40 CFR part 763, subpart E | Requires schools to inspect for asbestos and implement response actions and submit asbestos management plans to States. Specifies use of accredited inspectors, air sampling methods, and waste disposal procedures. |
| | 40 CFR part 427 | Effluent standards for asbestos manufacturing source categories. |
| | 40 CFR part 763, subpart G | Protects public employees performing asbestos abatement work in States not covered by OSHA asbestos standard. |
- 40 CFR 61.156 (enhanced display)

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Agency	CFR citation	Comment
OSHA	29 CFR 1910.1001	Worker protection measures-engineering controls, worker training, labeling, respiratory protection, bagging of waste, permissible exposure level.
	29 CFR 1926.1101	Worker protection measures for all construction work involving asbestos, including demolition and renovation-work practices, worker training, bagging of waste, permissible exposure level.
MSHA	30 CFR part 56, subpart D	Specifies exposure limits, engineering controls, and respiratory protection measures for workers in surface mines.
	30 CFR part 57, subpart D	Specifies exposure limits, engineering controls, and respiratory protection measures for workers in underground mines.
DOT	49 CFR parts 171 and 172	Regulates the transportation of asbestos-containing waste material. Requires waste containment and shipping papers.

[55 FR 48432, Nov. 20, 1990, as amended at 60 FR 31920, June 19, 1995; 68 FR 54793, Sept. 18, 2003; 69 FR 43324, July 20, 2004]

§ 61.157 Delegation of authority.

- (a) In delegating implementation and enforcement authority to a State under section 112(d) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.
- (b) Authorities that will not be delegated to States:
 - (1) Section 61.149(c)(2)
 - (2) Section 61.150(a)(4)
 - (3) Section 61.151(c)
 - (4) Section 61.152(b)(3)
 - (5) Section 61.154(d)
 - (6) Section 61.155(a).

[55 FR 48433, Nov. 20, 1990]

Appendix A to Subpart M of Part 61—Interpretive Rule Governing Roof Removal Operations

I. Applicability of the Asbestos NESHAP

1.1. Asbestos-containing material (ACM) is material containing more than one percent asbestos as determined using the methods specified in appendix E, subpart E, 40 CFR part 763, section 1, Polarized Light Microscopy. The NESHAP classifies ACM as either “friable” or “nonfriable”. Friable ACM is ACM that, when dry, can be crumbled, pulverized or reduced to powder by hand pressure. Nonfriable ACM is ACM that, when dry, cannot be crumbled, pulverized or reduced to powder by hand pressure.

1.2. Nonfriable ACM is further classified as either Category I ACM or Category II ACM. Category I ACM and Category II ACM are distinguished from each other by their potential to release fibers when damaged. Category I ACM includes asbestos-containing gaskets, packings, resilient floor coverings, resilient floor covering mastic, and asphalt roofing products containing more than one percent asbestos. Asphalt roofing products which may contain asbestos include built-up roofing; asphalt-containing single ply membrane systems; asphalt shingles; asphalt-containing underlayment felts; asphalt-containing roof coatings and mastics; and asphalt-containing base flashings. ACM roofing products that use other bituminous or resinous binders (such as coal tars or pitches) are also considered to be Category I ACM. Category II ACM includes all other nonfriable ACM, for example, asbestos-cement (A/C) shingles, A/C tiles, and transite boards or panels containing more than one percent asbestos. Generally speaking, Category II ACM is more likely to become friable when damaged than is Category I ACM. The applicability of the NESHAP to Category I and II ACM depends on: (1) the condition of the material at the time of demolition or renovation, (2) the nature of the operation to which the material will be subjected, (3) the amount of ACM involved.

1.3. Asbestos-containing material regulated under the NESHAP is referred to as “regulated asbestos-containing material” (RACM). RACM is defined in § 61.141 of the NESHAP and includes: (1) friable asbestos-containing material; (2) Category I nonfriable ACM that has become friable; (3) Category I nonfriable ACM that has been or will be sanded, ground, cut, or abraded; or (4) Category II nonfriable ACM that has already been or is likely to become crumbled, pulverized, or reduced to powder. If the coverage threshold for RACM is met or exceeded in a renovation or demolition operation, then all friable ACM in the operation, and in certain situations, nonfriable ACM in the operation, are subject to the NESHAP.

A. Threshold Amounts of Asbestos-Containing Roofing Material

1. A.1. The NESHAP does not cover roofing projects on single family homes or on residential buildings containing four or fewer dwelling units. 40 CFR 61.141. For other roofing renovation projects, if the total asbestos-containing roof area undergoing renovation is less than 160 ft², the NESHAP does not apply, regardless of the removal method to be used, the type of material (Category I or II), or its condition (friable versus nonfriable). 40 CFR 61.145(a)(4). However, EPA would recommend the use of methods that damage asbestos-containing roofing material as little as possible. EPA has determined that where a rotating blade (RB) roof cutter or equipment that similarly damages the roofing material is used to remove Category I nonfriable asbestos-containing roofing material, the removal of 5580 ft² of that material will create 160 ft² of RACM. For the purposes of this interpretive rule, “RB roof cutter” means an engine-powered roof cutting machine with one or more rotating cutting blades the edges of which are blunt. (Equipment with blades having sharp or tapered edges, and/or which does not use a rotating blade, is used for “slicing” rather than “cutting” the roofing material; such equipment is not included in the term “RB roof cutter”.) Therefore, it is EPA’s interpretation that when an RB roof cutter or equipment that similarly damages the roofing material is used to remove Category I nonfriable asbestos-containing roofing material, any project that is 5580 ft² or greater is subject to the NESHAP; conversely, it is EPA’s interpretation that when an RB roof cutter or

equipment that similarly damages the roofing material is used to remove Category I nonfriable asbestos-containing roofing material in a roof removal project that is less than 5580 ft², the project is not subject to the NESHAP, except that notification is always required for demolitions. EPA further construes the NESHAP to mean that if slicing or other methods that do not sand, grind, cut or abrade will be used on Category I nonfriable ACM, the NESHAP does not apply, regardless of the area of roof to be removed.

1.A.2. For asbestos cement (A/C) shingles (or other Category II roofing material), if the area of the roofing material to be removed is at least 160 ft² and the removal methods will crumble, pulverize, reduce to powder, or contaminate with RACM (from other ACM that has been crumbled, pulverized or reduced to powder) 160 ft² or more of such roofing material, the removal is subject to the NESHAP. Conversely, if the area of the A/C shingles (or other Category II roofing materials) to be removed is less than 160 ft², the removal is not subject to the NESHAP regardless of the removal method used, except that notification is always required for demolitions. 40 CFR 61.145(a). However, EPA would recommend the use of methods that damage asbestos-containing roofing material as little as possible. If A/C shingles (or other Category II roofing materials) are removed without 160 ft² or more of such roofing material being crumbled, pulverized, reduced to powder, or contaminated with RACM (from other ACM that has been crumbled, pulverized or reduced to powder), the operation is not subject to the NESHAP, even where the total area of the roofing material to be removed exceeds 160 ft²; provided, however, that if the renovation includes other operations involving RACM, the roof removal operation is covered if the total area of RACM from all renovation activities exceeds 160 ft². See the definition of regulated asbestos-containing material (RACM), 40 CFR 61.141.

1.A.3. Only roofing material that meets the definition of ACM can qualify as RACM subject to the NESHAP. Therefore, to determine if a removal operation that meets or exceeds the coverage threshold is subject to the NESHAP, any suspect roofing material (*i.e.* roofing material that may be ACM) should be tested for asbestos. If any such roofing material contains more than one percent asbestos and if the removal operation is covered by the NESHAP, then EPA must be notified and the work practices in § 61.145(c) must be followed. In EPA's view, if a removal operation involves at least the threshold level of suspect material, a roofing contractor may choose not to test for asbestos if the contractor follows the notification and work practice requirements of the NESHAP.

B. A/C Shingle Removal (Category II ACM Removal)

1.B.1. A/C shingles, which are Category II nonfriable ACM, become regulated ACM if the material has a high probability of becoming or has become crumbled, pulverized or reduced to powder by the forces expected to act on the material in the course of demolition or renovation operations. 40 CFR 61.141. However, merely breaking an A/C shingle (or any other category II ACM) that is not friable may not necessarily cause the material to become RACM. A/C shingles are typically nailed to buildings on which they are attached. EPA believes that the extent of breakage that will normally result from carefully removing A/C shingles and lowering the shingles to the ground will not result in crumbling, pulverizing or reducing the shingles to powder. Conversely, the extent of breakage that will normally occur if the A/C shingles are dropped from a building or scraped off of a building with heavy machinery would cause the shingles to become RACM. EPA therefore construes the NESHAP to mean that the removal of A/C shingles that are not friable, using methods that do not crumble, pulverize, or reduce the

A/C shingles to powder (such as pry bars, spud bars and shovels to carefully pry the material), is not subject to the NESHAP provided that the A/C shingles are properly handled during and after removal, as discussed in this paragraph and the asbestos NESHAP. This interpretation also applies to other Category II nonfriable asbestos-containing roofing materials.

C. Cutting vs. Slicing and Manual Methods for Removal of Category I ACM

1.C.1. Because of damage to the roofing material, and the potential for fiber release, roof removal operations using rotating blade (RB) roof cutters or other equipment that sand, grind, cut or abrade the roof material are subject to the NESHAP. As EPA interprets the NESHAP, the use of certain manual methods (using equipment such as axes, hatchets, or knives, spud bars, pry bars, and shovels, but not saws) or methods that slice, shear, or punch (using equipment such as a power slicer or power plow) does not constitute "cutting, sanding, grinding or abrading." This is because these methods do not destroy the structural matrix or integrity of the material such that the material is crumbled, pulverized or reduced to powder. Hence, it is EPA's interpretation that when such methods are used, assuming the roof material is not friable, the removal operation is not subject to the regulation.

1.C.2. Power removers or power tear-off machines are typically used to pry the roofing material up from the deck after the roof membrane has been cut. It is EPA's interpretation that when these machines are used to pry roofing material up, their use is not regulated by the NESHAP.

1.C.3. As noted previously, the NESHAP only applies to the removal of asbestos-containing roofing materials. Thus, the NESHAP does not apply to the use of RB cutters to remove non-asbestos built up roofing (BUR). On roofs containing some asbestos-containing and some non-asbestos-containing materials, coverage under the NESHAP depends on the methods used to remove each type of material in addition to other coverage thresholds specified above. For example, it is not uncommon for existing roofs to be made of non-asbestos BUR and base flashings that do contain asbestos. In that situation, EPA construes the NESHAP to be inapplicable to the removal of the non-asbestos BUR using an RB cutter so long as the RB cutter is not used to cut 5580 ft² or more of the asbestos-containing base flashing or other asbestos-containing material into sections. In addition, the use of methods that slice, shear, punch or pry could then be used to remove the asbestos flashings and not trigger coverage under the NESHAP.

II. Notification

2.1. Notification for a demolition is always required under the NESHAP. However, EPA believes that few roof removal jobs constitute "demolitions" as defined in the NESHAP (§ 61.141). In particular, it is EPA's view that the removal of roofing systems (i.e., the roof membrane, insulation, surfacing, coatings, flashings, mastic, shingles, and felt underlayment), when such removal is not a part of a demolition project, constitutes a "renovation" under the NESHAP. If the operation is a renovation, and Category I roofing material is being removed using either manual methods or slicing, notification is not required by the NESHAP. If Category II material is not friable and will be removed without crumbling, pulverizing, or reducing it to powder, no notification is required. Also, if the renovation involves less than the threshold area for

applicability as discussed above, then no notification is required. However, if a roof removal meets the applicability and threshold requirements under the NESHAP, then EPA (or the delegated agency) must be notified in advance of the removal in accordance with the requirements of § 61.145(b), as follows:

- Notification must be given in writing at least 10 working days in advance and must include the information in § 61.145(b)(4), except for emergency renovations as discussed below.
- The notice must be updated as necessary, including, for example, when the amount of asbestos-containing roofing material reported changes by 20 percent or more.
- EPA must be notified if the start date of the roof removal changes. If the start date of a roof removal project is changed to an earlier date, EPA must be provided with a written notice of the new start date at least 10 working days in advance. If the start date changes to a later date, EPA must be notified by telephone as soon as possible before the original start date and a written notice must be sent as soon as possible.
- For emergency renovations (as defined in § 61.141), where work must begin immediately to avoid safety or public health hazards, equipment damage, or unreasonable financial burden, the notification must be postmarked or delivered to EPA as soon as possible, but no later than the following work day.

III. Emission Control Practices

A. Requirements To Adequately Wet and Discharge No Visible Emission

3.A.1. The principal controls contained in the NESHAP for removal operations include requirements that the affected material be adequately wetted, and that asbestos waste be handled, collected, and disposed of properly. The requirements for disposal of waste materials are discussed separately in section IV below. The emission control requirements discussed in this section III apply only to roof removal operations that are covered by the NESHAP as set forth in Section I above.

3. A.2. For any operation subject to the NESHAP, the regulation (§§ 61.145(c)(2)(i), (3), (6)(i)) requires that RACM be adequately wet (as defined in § 61.141) during the operation that damages or disturbs the asbestos material until collected for disposal.

3.A.3. When using an RB roof cutter (or any other method that sands, grinds, cuts or abrades the roofing material) to remove Category I asbestos-containing roofing material, the emission control requirements of § 61.145(c) apply as discussed in Section I above. EPA will consider a roof removal project to be in compliance with the “adequately wet” and “discharge no visible emission” requirements of the NESHAP if the RB roof cutter is equipped and operated with the following: (1) a blade guard that completely encloses the blade and extends down close to the roof surface; and (2) a device for spraying a fine mist of water inside the blade guard, and which device is in operation during the cutting of the roof.

B. Exemptions From Wetting Requirements

3. B.1. The NESHAP provides that, in certain instances, wetting may not be required during the cutting of Category I asbestos roofing material with an RB roof cutter. If EPA determines in accordance with § 61.145(c)(3)(i), that wetting will unavoidably damage the building, equipment inside the building, or will present a safety hazard while stripping the ACM from a facility component that remains in place, the roof removal operation will be exempted from the requirement to wet during cutting. EPA must have sufficient written information on which to base such a decision. Before proceeding with a dry removal, the contractor must have received EPA's written approval. Such exemptions will be made on a case-by-case basis.
3. B.2. It is EPA's view that, in most instances, exemptions from the wetting requirements are not necessary. Where EPA grants an exemption from wetting because of the potential for damage to the building, damage to equipment within the building or a safety hazard, the NESHAP specifies alternative control methods (§ 61.145(c)(3)(i)(B)). Alternative control methods include (a) the use of local exhaust ventilation systems that capture the dust, and do not produce visible emissions, or (b) methods that are designed and operated in accordance with the requirements of § 61.152, or (c) other methods that have received the written approval of EPA. EPA will consider an alternative emission control method in compliance with the NESHAP if the method has received written approval from EPA and the method is being implemented consistent with the approved procedures (§ 61.145(c)(3)(ii) or § 61.152(b)(3)).
3. B.3. An exemption from wetting is also allowed when the air or roof surface temperature at the point of wetting is below freezing, as specified in § 61.145(c)(7). If freezing temperatures are indicated as the reason for not wetting, records must be kept of the temperature at the beginning, middle and end of the day on which wetting is not performed and the records of temperature must be retained for at least 2 years. 42 CFR § 61.145(c)(7)(iii). It is EPA's interpretation that in such cases, no written application to, or written approval by the Administrator is needed for using emission control methods listed in § 61.145(c)(3)(i)(B), or alternative emission control methods that have been previously approved by the Administrator. However, such written application or approval is required for alternative emission control methods that have not been previously approved. Any dust and debris collected from cutting must still be kept wet and placed in containers. All of the other requirements for notification and waste disposal would continue to apply as described elsewhere in this notice and the Asbestos NESHAP.

C. Waste Collection and Handling

3. C.1. It is EPA's interpretation that waste resulting from slicing and other methods that do not cut, grind, sand or abrade Category I nonfriable asbestos-containing roofing material is not subject to the NESHAP and can be disposed of as nonasbestos waste. EPA further construes the NESHAP to provide that if Category II roofing material (such as A/C shingles) is removed and disposed of without crumbling, pulverizing, or reducing it to powder, the waste from the removal is not subject to the NESHAP waste disposal requirements. EPA also interprets the NESHAP to be inapplicable to waste resulting from roof removal operations that do not meet or exceed the coverage thresholds described in section I above. Of course, other State, local, or Federal regulations may apply.
3. C.2. It is EPA's interpretation that when an RB roof cutter, or other method that similarly damages the roofing material, is used to cut Category I asbestos containing roofing material, the damaged material from the cut (the sawdust or debris) is considered asbestos containing

waste subject to § 61.150 of the NESHAP, provided the coverage thresholds discussed above in section 1 are met or exceeded. This sawdust or debris must be disposed of at a disposal site operated in accordance with the NESHAP. It is also EPA's interpretation of the NESHAP that if the remainder of the roof is free of the sawdust and debris generated by the cutting, or if such sawdust or debris is collected as discussed below in paragraphs 3.C.3, 3.C.4, 3.C.5 and 3.C.6, the remainder of the roof can be disposed of as nonasbestos waste because it is considered to be Category I nonfriable material (as long as the remainder of the roof is in fact nonasbestos material or if it is Category I asbestos material and the removal methods do not further sand, grind, cut or abrade the roof material). EPA further believes that if the roof is not cleaned of such sawdust or debris, *i.e.*, it is contaminated, then it must be treated as asbestos-containing waste material and be handled in accordance with § 61.150.

3. C.3. In order to be in compliance with the NESHAP while using an RB roof cutter (or device that similarly damages the roofing material) to cut Category I asbestos containing roofing material, the dust and debris resulting from the cutting of the roof should be collected as soon as possible after the cutting operation, and kept wet until collected and placed in leak-tight containers. EPA believes that where the blade guard completely encloses the blade and extends down close to the roof surface and is equipped with a device for spraying a fine mist of water inside the blade guard, and the spraying device is in operation during the cutting, most of the dust and debris from cutting will be confined along the cut. The most efficient methods to collect the dust and debris from cutting are to immediately collect or vacuum up the damaged material where it lies along the cut using a filtered vacuum cleaner or debris collector that meets the requirements of 40 CFR 61.152 to clean up as much of the debris as possible, or to gently sweep up the bulk of the debris, and then use a filtered vacuum cleaner that meets the requirements of 40 CFR 61.152 to clean up as much of the remainder of the debris as possible. On smooth surfaced roofs (nonaggregate roofs), sweeping up the debris and then wet wiping the surface may be done in place of using a filtered vacuum cleaner. It is EPA's view that if these decontamination procedures are followed, the remaining roofing material does not have to be collected and disposed of as asbestos waste. Additionally, it is EPA's view that where such decontamination procedures are followed, if the remaining portions of the roof are non-asbestos or Category I nonfriable asbestos material, and if the remaining portions are removed using removal methods that slice, shear, punch or pry, as discussed in section 1.C above, then the remaining portions do not have to be collected and disposed of as asbestos waste and the NESHAP's no visible emissions and adequately wet requirements are not applicable to the removal of the remaining portions. In EPA's interpretation, the failure of a filtered vacuum cleaner or debris collector to collect larger chunks or pieces of damaged roofing material created by the RB roof cutter does not require the remaining roofing material to be handled and disposed of as asbestos waste, provided that such visible chunks or pieces of roofing material are collected (e.g. by gentle sweeping) and disposed of as asbestos waste. Other methods of decontamination may not be adequate, and should be approved by the local delegated agency.
3. C.4. In EPA's interpretation, if the debris from the cutting is not collected immediately, it will be necessary to lightly mist the dust or debris, until it is collected, as discussed above, and placed in containers. The dust or debris should be lightly misted frequently enough to prevent the material from drying, and to prevent airborne emissions, prior to collection as described above. It is EPA's interpretation of the NESHAP that if these procedures are followed, the remaining roofing material does not have to be collected and disposed of as asbestos waste, as long as the remaining roof material is in fact nonasbestos material or if it is Category I asbestos material and the removal methods do not further sand, grind, cut or abrade the roof material.

3. C.

5. It is EPA's interpretation that, provided the roofing material is not friable prior to the cutting operation, and provided the roofing material has not been made friable by the cutting operation, the appearance of rough, jagged or damaged edges on the remaining roofing material, due to the use of an RB roof cutter, does not require that such remaining roofing material be handled and disposed of as asbestos waste. In addition, it is also EPA's interpretation that if the sawdust or debris generated by the use of an RB roof cutter has been collected as discussed in paragraphs 3.C.3, 3.C.4 and 3.C.6, the presence of dust along the edge of the remaining roof material does not render such material "friable" for purposes of this interpretive rule or the NESHAP, provided the roofing material is not friable prior to the cutting operation, and provided that the remaining roofing material near the cutline has not been made friable by the cutting operation. Where roofing material near the cutline has been made friable by the use of the RB cutter (*i.e.* where such remaining roofing material near the cutline can be crumbled, pulverized or reduced to powder using hand pressure), it is EPA's interpretation that the use of an encapsulant will ensure that such friable material need not be treated or disposed of as asbestos containing waste material. The encapsulant may be applied to the friable material after the roofing material has been collected into stacks for subsequent disposal as nonasbestos waste. It is EPA's view that if the encapsulation procedure set forth in this paragraph is followed in operations where roofing material near the cutline has been rendered friable by the use of an RB roof cutter, and if the decontamination procedures set forth in paragraph 3.C.3 have been followed, the NESHAP's no visible emissions and adequately wet requirements would be met for the removal, handling and disposal of the remaining roofing material.

3.C.6. As one way to comply with the NESHAP, the dust and debris from cutting can be placed in leak-tight containers, such as plastic bags, and the containers labeled using warning labels required by OSHA (29 CFR 1926.58). In addition, the containers must have labels that identify the waste generator (such as the name of the roofing contractor, abatement contractor, and/or building owner or operator) and the location of the site at which the waste was generated.

IV. Waste Disposal

A. Disposal Requirements

4.A.1. Section 61.150(b) requires that, as soon as is practical, all collected dust and debris from cutting as well as any contaminated roofing squares, must be taken to a landfill that is operated in accordance with § 61.154 or to an EPA-approved site that converts asbestos waste to nonasbestos material in accordance with § 61.155. During the loading and unloading of affected waste, asbestos warning signs must be affixed to the vehicles.

B. Waste Shipment Record

4.B.1. For each load of asbestos waste that is regulated under the NESHAP, a waste shipment record (WSR) must be maintained in accordance with § 61.150(d). Information that must be maintained for each waste load includes the following:

- Name, address, and telephone number of the waste generator
- Name and address of the local, State, or EPA regional office responsible for administering the asbestos NESHAP program
- Quantity of waste in cubic meters (or cubic yards)
- Name and telephone number of the disposal site operator
- Name and physical site location of the disposal site
- Date transported
- Name, address, and telephone number of the transporter(s)
- Certification that the contents meet all government regulations for transport by highways.

4.B.2. The waste generator is responsible for ensuring that a copy of the WSR is delivered to the disposal site along with the waste shipment. If a copy of the WSR signed by the disposal site operator is not returned to the waste generator within 35 days, the waste generator must contact the transporter and/or the disposal site to determine the status of the waste shipment. 40 CFR 61.150(d)(3). If the signed WSR is not received within 45 days, the waste generator must report, in writing, to the responsible NESHAP program agency and send along a copy of the WSR. 40 CFR 61.150(d)(4). Copies of WSRs, including those signed by the disposal site operator, must be retained for at least 2 years. 40 CFR 61.150(d)(5).

V. Training

- 5.1. For those roof removals that are subject to the NESHAP, at least one on-site supervisor trained in the provisions of the NESHAP must be present during the removal of the asbestos roofing material. 40 CFR 61.145(c)(8). In EPA's view, this person can be a job foreman, a hired consultant, or someone who can represent the building owner or contractor responsible for the removal. In addition to the initial training requirement, a refresher training course is required every 2 years. The NESHAP training requirements became effective on November 20, 1991.
- 5.2. Asbestos training courses developed specifically to address compliance with the NESHAP in roofing work, as well as courses developed for other purposes can satisfy this requirement of the NESHAP, as long as the course covers the areas specified in the regulation. EPA believes that Asbestos Hazard Emergency Response Act (AHERA) training courses will, for example, satisfy the NESHAP training requirements. However, nothing in this interpretive rule or in the NESHAP shall be deemed to require that roofing contractors or roofing workers performing operations covered by the NESHAP must be trained or accredited under AHERA, as amended by the Asbestos School Hazard Abatement Reauthorization Act (ASHARA). Likewise, state or local authorities may independently impose additional training, licensing, or accreditation requirements on roofing contractors performing operations covered by the NESHAP, but such additional training, licensing or accreditation is not called for by this interpretive rule or the federal NESHAP.
- 5.3. For removal of Category I asbestos containing roofing material where RB roof cutters or equipment that similarly damages the asbestos-containing roofing material are used, the NESHAP training requirements (§ 61.145(c)(8)) apply as discussed in Section I above. It is

EPA's intention that removal of Category I asbestos-containing roofing material using hatchets, axes, knives, and/or the use of spud bars, pry bars and shovels to lift the roofing material, or similar removal methods that slice, punch, or shear the roof membrane are not subject to the training requirements, since these methods do not cause the roof removal to be subject to the NESHAP. Likewise, it is EPA's intention that roof removal operations involving Category II nonfriable ACM are not subject to the training requirements where such operations are not subject to the NESHAP as discussed in section I above.

[59 FR 31158, June 17, 1994, as amended at 60 FR 31920, June 19, 1995]

Appendix H

40 C.F.R. § 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 63 —National Emission Standards for Hazardous Air Pollutants for Source Categories

Authority: 42 U.S.C. 7401 *et seq.*

Source: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

What This Subpart Covers

- § 63.6580 What is the purpose of subpart ZZZZ?
- § 63.6585 Am I subject to this subpart?
- § 63.6590 What parts of my plant does this subpart cover?
- § 63.6595 When do I have to comply with this subpart?

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?
- § 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?
- § 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?
- § 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?
- § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

General Compliance Requirements

- § 63.6605 What are my general requirements for complying with this subpart?

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?
- § 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?

§ 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?

§ 63.6615 When must I conduct subsequent performance tests?

§ 63.6620 What performance tests and other procedures must I use?

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

§ 63.6650 What reports must I submit and when?

§ 63.6655 What records must I keep?

§ 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

§ 63.6670 Who implements and enforces this subpart?

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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

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

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 $\geq$ 250 HP Located at a Major Source of HAP Emissions

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 $\geq$ 250
HP Located at a Major Source of HAP Emissions, Existing CI
Stationary RICE >500 HP

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 $\leq$ 500 HP Located at a Major
Source of HAP Emissions

Table 2d to Subpart ZZZZ of Part 63

Requirements for Existing Stationary RICE Located at Area
Sources of HAP Emissions

Table 3 to Subpart ZZZZ of Part 63

Subsequent Performance Tests

Table 4 to Subpart ZZZZ of Part 63

Requirements for Performance Tests

Table 5 to Subpart ZZZZ of Part 63

Initial Compliance With Emission Limitations, Operating
Limitations, and Other Requirements

Table 6 to Subpart ZZZZ of Part 63

Continuous Compliance With Emission Limitations, and Other
Requirements

Table 7 to Subpart ZZZZ of Part 63

Requirements for Reports

Table 8 to Subpart ZZZZ of Part 63

Applicability of General Provisions to Subpart ZZZZ

Appendix A to Subpart ZZZZ of Part 63

Protocol for Using an Electrochemical Analyzer to Determine
Oxygen and Carbon Monoxide Concentrations From Certain
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:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 1})$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(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 (CO₂). If pollutant concentrations are to be corrected to 15 percent oxygen and CO₂ concentration is measured in lieu of oxygen concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ 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:

$$F_O = \frac{0.209 F_d}{F_C} \quad (Eq. 2)$$

Where:

F_O = Fuel factor based on the ratio of oxygen volume to the ultimate CO₂ volume produced by the fuel at zero percent excess air.

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

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

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

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

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq. 3)$$

Where:

X_{CO2} = CO₂ correction factor, percent.

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

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O₂ using CO₂ as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O₂.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO_2} = CO₂ correction factor, percent.

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

- (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 O₂ or CO₂ 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 CO₂ 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 O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ 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 O₂ 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 O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ 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 O₂ 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 CO₂.

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 CO₂.

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 CO₂, 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 C₃H₈.

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

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
	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 existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP	Comply with any operating limitations approved by the Administrator.

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
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 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 O ₂ . 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 O ₂ 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 O ₂	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 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 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	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
oxidation catalyst 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 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.	a. 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 Comply with any operating limitations approved by the Administrator.

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; 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	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

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
5. Non-Emergency, non-black start stationary CI RICE >500 HP 6. Emergency stationary SI RICE and black start stationary SI RICE.¹	b. Reduce CO emissions by 70 percent or more a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more 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 necessary³	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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 necessary³	
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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	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	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	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.*

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; 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	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 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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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	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 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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
6. Non-emergency, non-black start 2SLB stationary RICE	within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary 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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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 10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	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 Install an oxidation catalyst to reduce HAP emissions from the stationary RICE a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	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 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	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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 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	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 Install NSCR to reduce HAP emissions from the 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;¹ b. Inspect spark plugs every 1,440 hours of operation or	

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.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	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 $\geq$ 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 $\geq$ 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 $250 \leq \text{HP} \leq 500$ 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 ii. Measure the O₂ 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)	(a) For CO, O₂, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A-4. (b) Measurements to determine O₂ must be made at the same time as the measurements for CO concentration.

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.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	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.
		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 <i>and</i> the sampling port location meets the two and half-diameter criterion of section 11.1.1 of

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.

For each . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		ii. Measure O₂ at the inlet and outlet of the control device; and iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O₂ concentrations on a dry basis; and iv. If demonstrating compliance	(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) (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} (3) Method 320 or 323 of 40 CFR	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. (b) Measurements to determine O₂ concentration must be made at the same time as the measurements for formaldehyde or THC concentration. (c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration. (d) Formaldehyde concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the

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.

For each . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	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	three 1-hour or longer runs.
		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	i. Select the sampling port location and the number/ location of traverse points		(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

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.

For each . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
	RICE exhaust	at the exhaust of the stationary RICE; and		points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, 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	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63,	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.

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.

For each . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		needed to determine formaldehyde or CO and O₂ concentrations on a dry basis; and iv. Measure formaldehyde at the exhaust of the stationary RICE; or v. Measure CO at the exhaust of the stationary RICE	appendix A, or ASTM D6348-03^{1 3} (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 (4) Method 10 of 40 CFR part 60, appendix A-4, ASTM D6522-00 (2005),^{1 3} method 320	(d) Formaldehyde concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs. (e) CO concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

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.*

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
			of 40 CFR part 63, appendix A, or ASTM D6348-03 ¹ ₃	

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.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
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

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
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	operating parameters (if any) during the initial performance test. i. You have installed a CEMS to continuously monitor CO and either O₂ or CO₂ 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 O₂ or CO₂ 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	i. The average reduction of emissions of formaldehyde

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
	emissions and using NSCR	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	a. Limit the concentration of formaldehyde in the stationary	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

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
stationary RICE >500 HP located at a major source of HAP	RICE exhaust and using oxidation catalyst or NSCR	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 O₂, 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	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
that are operated more than 24 hours per calendar year		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

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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 $\geq$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	drop across the catalyst is within the operating limitation established during the performance test. 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	a. Reduce CO emissions or	i. Collecting the monitoring data

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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	limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	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.

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
6. Non-emergency 4SRB stationary RICE with a brake HP $\geq 5,000$ located at a major source of HAP 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 $250 \leq \text{HP} \leq 500$ located at a major source of HAP	a. Reduce formaldehyde emissions a. Limit the concentration of formaldehyde in the stationary	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. 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 i. Conducting semiannual performance tests for formaldehyde to demonstrate that your

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	RICE exhaust and using oxidation catalyst or NSCR	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	a. Limit the concentration	i. Conducting semiannual
^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.		

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP	of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	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	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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		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

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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,	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. i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	and not using oxidation catalyst	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	i. Conducting performance tests every 8,760 hours or 5 years,

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	of CO in the stationary RICE exhaust, and using an oxidation catalyst	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

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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	demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. 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

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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	rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. 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 O₂; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages;

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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	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. 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 O₂, or the average reduction of emissions of THC is 30 percent or more; and either

^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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		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 $100 \leq \text{HP} \leq 500$ 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 or reconstructed non-emergency stationary RICE > 500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP	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 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 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)(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 numerical emission limitations. i. Semiannually according to the requirements in § 63.6650(b) and (i). i. Semiannually according to the requirements in § 63.6650(b) and (i).

For each . . .	You must submit a . . .	The report must contain . .	You must submit the report . . .
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 b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and c. Any problems or errors suspected with the meters	i. Annually, according to the requirements in § 63.6650. i. See item 2.a.i. 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	Additional terms defined in § 63.6675.
§ 63.2	Definitions	Yes	
§ 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	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 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	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
	operation and maintenance		
§ 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	Yes	Except that § 63.9(c) only applies as

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.9(d)	extension Notification of special compliance requirements for new sources	Yes	specified in § 63.6645. 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	
§	Record when under	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
63.10(b)(2)(xii)	waiver		
§ 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 (O₂) 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 (O₂).

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 (O ₂)	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 O₂, 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 O₂ 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 O₂ 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 O₂ 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 NO₂ 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 O₂ 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 O₂; 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 O₂. 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 O₂) is acceptable for calibration of the O₂ cell. If needed, any lower percentage O₂ calibration gas must be a mixture of O₂ 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 O₂ 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 O₂. When the average exhaust gas O₂ readings are above 6 percent, you may use dry ambient air (20.9 percent O₂) for the up-scale O₂ 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., CO₂).

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 O₂ 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 O₂ 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 O₂ for the O₂ 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 O₂, 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 O₂, 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 O₂ 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.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

- 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 NO₂ gas standards that are generally recognized as representative of diesel-fueled engine NO and NO₂ 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 NO₂ 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											
"											
"											
"											
"											
"											
"											
"											
"											
Mean Refresh Phase											
"											
"											
"											
"											

[78 FR 6721, Jan. 30, 2013]

Appendix I

40 C.F.R. § 63, Subpart UUUUU - *National Emission Standards for Hazardous Air Pollutants:
Coal- and Oil-Fired Electric Utility Steam Generating Units*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 63 —National Emission Standards for Hazardous Air Pollutants for Source Categories

Authority: 42 U.S.C. 7401 *et seq.*

Source: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart UUUUU National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

- § 63.9980 What is the purpose of this subpart?
- § 63.9981 Am I subject to this subpart?
- § 63.9982 What is the affected source of this subpart?
- § 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?
- § 63.9984 When do I have to comply with this subpart?
- § 63.9985 What is a new EGU?

Emission Limitations and Work Practice Standards

- § 63.9990 What are the subcategories of EGUs?
- § 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

General Compliance Requirements

- § 63.10000 What are my general requirements for complying with this subpart?
- § 63.10001 *[Reserved]*

Testing and Initial Compliance Requirements

- § 63.10005 What are my initial compliance requirements and by what date must I conduct them?
- § 63.10006 When must I conduct subsequent performance tests or tune-ups?
- § 63.10007 What methods and other procedures must I use for the performance tests?
- § 63.10008 *[Reserved]*
- § 63.10009 May I use emissions averaging to comply with this subpart?
- § 63.10010 What are my monitoring, installation, operation, and maintenance requirements?
- § 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

Continuous Compliance Requirements

- § 63.10020 How do I monitor and collect data to demonstrate continuous compliance?
- § 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
- § 63.10022 How do I demonstrate continuous compliance under the emissions averaging

provision?

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

§ 63.10031 What reports must I submit and when?

§ 63.10032 What records must I keep?

§ 63.10033 In what form and how long must I keep my records?

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

§ 63.10041 Who implements and enforces this subpart?

§ 63.10042 What definitions apply to this subpart?

Table 1 to Subpart UUUUU of Part 63

Emission Limits for New or Reconstructed EGUs

Table 2 to Subpart UUUUU of Part 63

Emission Limits for Existing EGUs

Table 3 to Subpart UUUUU of Part 63

Work Practice Standards

Table 4 to Subpart UUUUU of Part 63

Operating Limits for EGUs

Table 5 to Subpart UUUUU of Part 63

Performance Testing Requirements

Table 6 to Subpart UUUUU of Part 63

Establishing PM CPMS Operating Limits

Table 7 to Subpart UUUUU of Part 63

Demonstrating Continuous Compliance

Table 8 to Subpart UUUUU of Part 63

Reporting Requirements

Table 9 to Subpart UUUUU of Part 63

Applicability of General Provisions to Subpart UUUUU

Appendix A to Subpart UUUUU of Part 63

Hg Monitoring Provisions

Appendix B to Subpart UUUUU of Part 63

-HCl and HF Monitoring Provisions

Appendix C to Subpart UUUUU of Part 63

PM Monitoring Provisions

Appendix D to Subpart UUUUU of Part 63

PM CPMS Monitoring Provisions

Appendix E to Subpart UUUUU of Part 63

Data Elements

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 YYYYY 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 (SO₂) 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) Before July 6, 2027, 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 SO₂ 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 SO₂ 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 SO₂ 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]

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) through (C) of this section:

- (A) Except as provided in paragraph (c)(1)(i)(D) 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) On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for coal-fired and solid oil-derived fuel-fired EGUs.
- (D) 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)
 - (A) Before July 6, 2027, if your coal-fired or solid oil derived fuel-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, for an existing EGU, compliance performance testing repeated quarterly.
 - (B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.
 - (C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, 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, 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 (SO₂) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO₂ 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. On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals.
 - (ii) Before July 6, 2027, 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. On and after July 6, 2027, you may not pursue or continue to use the LEE option for your liquid oil-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.
 - (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 (which with the exception of IGCC units, are only applicable before July 6, 2027), 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]

§ 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. Before July 6, 2027, 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. On and after July 6, 2027, the requirements in Table 4 are not applicable, with the exception of IGCC units. 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 SO₂ 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 SO₂ 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, CO₂, O₂, 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 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 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, 5I, 5D, 6, 26A, or 29 test (e.g., pitot tube (delta P) readings, moisture collected in the impingers, etc.). 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 40 CFR 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. With the exception of IGCC units, on and after July 6, 2027, you may not demonstrate compliance with applicable filterable PM emissions limits with the use of PM CPMS or quarterly stack testing, you may only use PM CEMS.

- (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 SO₂, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO₂, 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 SO₂, 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 (with the exception of IGCC units, the use of PM CPMS is only allowed before July 6, 2027):
- (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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. 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) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), 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 (CO₂ or O₂) 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 CO₂ (or O₂) 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 µg/m³ (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 CO₂ or O₂ 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.

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§ 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 before July 6, 2027 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. On or after July 6, 2027 you may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs. This prohibition against the use of PM CPMS does not apply to IGCC units.
- (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 SO₂ CEMS to monitor compliance with the alternate equivalent SO₂ 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.

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§ 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, SO₂, 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 (the use of PM CPMS is only allowed before July 6, 2027 with the exception of IGCC units), 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. On and after July 6, 2027, you must demonstrate continuous compliance with the applicable filterable PM emission standard through the use of a PM CEMS (with the exception that IGCC units are not required to use PM CEMS and may continue to use PM CPMS). Alternatively, you may demonstrate continuous compliance with the non-Hg metals emission standard if you request and receive approval for the use of a HAP metals CMS under § 63.7(f).
- (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 SO₂ 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 SO₂, 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 SO₂, 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 10³ 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, SO₂, 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 CO₂ concentration is below the cap value or the measured O₂ concentration is above the cap value:
 - (i) For an IGCC EGU, you may use 1% for CO₂ or 19% for O₂.
 - (ii) For all other EGUs, you may use 5% for CO₂ or 14% for O₂.
- (2) **Default gross output.** If you use CEMS to continuously monitor Hg, HCl, HF, SO₂, 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]

§ 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, SO₂, 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 $\geq 8,300$ 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 $\geq 8,300$ 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.**

$$WAER_m = \frac{[\sum_{j=1}^p Herm_j \times Rmm_j] + \sum_{k=1}^m Ter_k \times Rmt_k}{(\sum_{j=1}^p Rmm_j) + \sum_{k=1}^m Rmt_k} \quad (Eq. 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{ij}$ = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j ,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j ,

p = number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k ,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k , and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum \left[\left(\sum_{j=1}^p Herm_{i,j} \right) \times Smm_j \times Cfm_j \right] + \sum_{k=1}^m Ter_k \times Smt_k \times Cft_k}{\sum \left[\sum_{j=1}^p Smm_j \times Cfm_j \right] + \sum_{k=1}^m Smt_k \times Cft_k} \quad (Eq. 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

- (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.

$$WAER = \frac{\sum_{i=1}^p \left[\sum_{t=1}^n (Her_i \times Rm_i) \right]_p + \sum_{i=1}^m (Ter_i \times Rt_i)}{\sum_{i=1}^p \left[\sum_{t=1}^n (Rm_i) \right]_p + \sum_{i=1}^m Rt_i} \quad (Eq. 2a)$$

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS or sorbent trap monitoring system for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^p \left[\sum_{t=1}^n (Her_i \times Sm_i \times Cfm_i) \right]_p + \sum_{i=1}^m (Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^p \left[\sum_{t=1}^n (Sm_i \times Cfm_i) \right]_p + \sum_{i=1}^m St_i \times Cft_i} \quad (Eq. 2b)$$

Where:

variables with similar names share the descriptions for Equation 2a of this section,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

- (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.

$$WAER = \frac{\sum_{i=1}^p \left[\sum_{i=1}^n (Her_i \times Rm_i) \right]_p}{\sum_{i=1}^p \left[\sum_{i=1}^n (Rm_i) \right]_p} \quad (\text{Eq. 3a})$$

Where:

Her_i = Hourly emission rate from unit i 's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^p \left[\sum_{i=1}^n (Her_i \times Sm_i \times Cfm_i) \right]_p}{\sum_{i=1}^p \left[\sum_{i=1}^n (Sm_i \times Cfm_i) \right]_p} \quad (\text{Eq. 3b})$$

Where:

Her_i = Hourly emission rate from unit i's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses Hg CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses Hg CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

- (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, SO₂, 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, SO₂, 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, SO₂, 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, SO₂, 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 (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), 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 (O₂) or carbon dioxide (CO₂) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O₂ or CO₂ 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 O₂ or CO₂ 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 SO₂ 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 SO₂ 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 SO₂ CEMS has a span value of 30 ppm or less.
 - (3) Calculate and record a 30-boiler operating day rolling average SO₂ 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 SO₂ emission rates in the 30 boiler operating day period.
 - (4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ 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 SO₂ 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 SO₂ 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 (only applicable before July 6, 2027 unless it is for an IGCC unit), 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 (which on or after July 6, 2027 you may not use non-mercury metal HAP limits for compliance demonstrations for existing EGUs unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f)), 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. With the exception of IGCC units, on or after July 6, 2027 owners/operators of existing EGUs must comply with filterable PM emissions limits in Table 2 of this subpart and demonstrate continuous compliance using a PM CEMS unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f). 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]

§ 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 (with the exception of existing IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 4 p.m. CPMS operating limits do not apply), or if, for an IGCC unit, 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. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 6 procedures for establishing PM CPMS operating limits do not apply unless it is an IGCC unit.
- (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 SO₂ 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 SO₂ 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]

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 (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and you may not pursue or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), 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]

§ 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 SO₂, 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, CO₂, O₂, 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.

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^n Her_i}{n} \quad (\text{Eq. 8})$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

- (c) If you use PM CPMS data (only allowed before July 6, 2027 unless it is for an IGCC unit) 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 Equation 9 to determine the 30 boiler operating day average. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations unless it is for an IGCC unit.

$$30 \text{ boiler operating day average} = \frac{\sum_{i=1}^n Hpv_i}{n} \text{ (Eq. 9)}$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

- (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 O₂ 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 O₂ 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 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.
- (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]

§ 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. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;
 - (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. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.
 - (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]

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

The provisions of this section § 63.10023 are only applicable before July 6, 2027 unless it is for an IGCC unit. On or after July 6, 2027 you may not use PM CPMS, unless it is an IGCC unit, for demonstrating compliance with the filterable PM emissions limits of this subpart.

- (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 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 ($\bar{x}$) in milliamps, and the average of your corresponding three PM compliance test runs ($\bar{y}$), using equation 10.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

- (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.

$$R = \frac{\bar{y}}{(\bar{x} - z)} \quad (\text{Eq. 11})$$

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

$\bar{y}$ = the three run average PM lb/MWh,

$\bar{x}$ = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

- (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.

$$O_L = z + \frac{(0.75 \times L)}{R} \quad (\text{Eq. 12})$$

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

- (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.

$$O_h = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

X_i = the PM CPMS data points for all runs i ,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

- (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]

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—which on or after July 6, 2027—you may not use for filterable PM compliance demonstrations, unless it is for an IGCC unit); 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]

§ 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) Before July 6, 2027, if you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Except for IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations. 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 SO₂ emission rate continuously as a surrogate for HCl, you must use the ECMPS Client 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 SO₂ CEMS and for any additional monitoring systems that are required to convert SO₂ 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 SO₂ CEMS and for any additional monitoring systems that are required to convert SO₂ 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 SO₂ concentration (in ppm, rounded to one decimal place), and separate unadjusted hourly data streams for the other parameters needed to convert the SO₂ 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 SO₂ 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 SO₂ monitor and the additional monitors used to convert SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), 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 SO₂, 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 section 63.10030(e), as PDF files. Quarterly compliance reports shall be submitted in XML format 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 Client 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 Client 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 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 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 Client Tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each Notification.
- (i) If you have elected to use 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 include the information in 40 CFR 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 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you 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 this section must be entered into ECMPS 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 Client 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 paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.
- (k) If you elect to demonstrate compliance using a PM CPMS (on or after July 6, 2027 you may not demonstrate compliance with filterable PM emissions limits using a PM CPMS, unless it is for an IGCC unit) 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 paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS 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]

§ 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 (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), 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]

§ 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) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I ("Subpart I—Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel").

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 calendar 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 CO₂ or O₂ concentration that may be used to calculate the Hg, HCl, HF, PM, or SO₂ emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO₂ concentration is below the cap value or the measured O₂ 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 SO₂ 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 stream upstream of a PM control device to react with and neutralize acid gases (such as SO₂ 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 SO₂ 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 calendar 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 calendar 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.

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 $\geq 8,300$ 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 SO₂ 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]

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.
	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	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
2. Coal-fired units low rank virgin coal	Manganese (Mn)	4.0E-3 lb/GWh	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.
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	
	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.
	a. Filterable particulate matter (PM) ¹	9.0E-2 lb/MWh	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 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	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
3. IGCC unit	Arsenic (As)	3.0E-3 lb/GWh	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. SO ₂ CEMS. Hg CEMS or sorbent trap monitoring system only. Collect a minimum catch of 3.0 milligrams or a
	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	
	OR Sulfur dioxide (SO ₂) ³	1.0 lb/MWh	
	c. Mercury (Hg)	Before July 8, 2024: 4.0E-2 lb/GWh; On or after July 8, 2024: 1.3E-2 lb/GWh	
	a. Filterable	7.0E-2 lb/MWh	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
	particulate matter (PM) OR Total non-Hg HAP metals OR Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se) b. Hydrogen	⁴ 9.0E-2 lb/MWh ⁵ OR 4.0E-1 lb/GWh OR 2.0E-2 lb/GWh 2.0E-2 lb/GWh 1.0E-3 lb/GWh 2.0E-3 lb/GWh 4.0E-2 lb/GWh 4.0E-3 lb/GWh 9.0E-3 lb/GWh 2.0E-2 lb/GWh 7.0E-2 lb/GWh 3.0E-1 lb/GWh 2.0E-3 lb/MWh	minimum sample volume of 2 dscm per run. Collect a minimum of 1 dscm per run. Collect a minimum of 2 dscm per run. For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	chloride (HCl)		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.
	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	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	Chromium (Cr)	2.0E-2 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. 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. 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. Collect a minimum of 1 dscm per run.
	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	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	Collect a minimum of 1 dscm per run.
	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh ¹	
	OR Total HAP metals	OR 7.0E-3 lb/MWh	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
	OR Individual HAP metals: 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 b. Hydrogen chloride (HCl) 2.0E-3 lb/MWh c. 5.0E-4 lb/MWh	OR	Collect a minimum of 3 dscm per run. For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be $<^{1/2}$ the standard. 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. For Method 26A, collect a minimum of 3 dscm

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
6. Solid oil-derived fuel-fired unit	Hydrogen fluoride (HF)		per run. For ASTM D6348-03 (Reapproved 2010) ² or Method 320, sample for a minimum of 1 hour.
	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh ¹	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	

¹ Gross output.

² Incorporated by reference, see § 63.14.

³ You may not use the alternate SO₂ 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 SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

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 . . .
	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 SO₂ 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 SO₂ 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]

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)	Before July 6, 2027: 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh ² On or after July 6, 2027: 1.0E-2 lb/MMBtu or 1.0E-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.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals	Before July 6, 2027: 5.0E-5 lb/MMBtu or 5.0E-1 lb/	Collect a minimum of 1 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	OR Individual HAP metals: Antimony (Sb)	GWh On or after July 6, 2027: 1.7E-5 lb/MMBtu or 1.7E-1 lb/GWh OR Before July 6, 2027: 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 3 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Arsenic (As) Beryllium (Be) Cadmium	GWh Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E-2 lb/GWh On or after July 6, 2027: 3.7E-1 lb/TBtu or 6.7E-3 lb/GWh Before July 6, 2027: 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh On or after July 6, 2027: 6.7E-2 lb/TBtu or 6.7E-4 lb/GWh Before July	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 (<i>e.g.</i>, specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	(Cd)	6, 2027: 3.0E-1 lb/ TBtu or 3.0E-3 lb/ GWh On or after July 6, 2027: 1.0E-1 lb/ TBtu or 1.0E-3 lb/ GWh	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/ TBtu or 3.0E-2 lb/ GWh On or after July 6, 2027: 9.3E-1 lb/ TBtu or 1.0E-2 lb/ GWh	
	Cobalt (Co)	Before July 6, 2027: 8.0E-1 lb/ GWh	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . .
	Lead (Pb)	TBtu or 8.0E-3 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E-2 lb/GWh On or after July 6, 2027: 4.0E-1 lb/TBtu or 6.7E-3 lb/GWh	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E-2 lb/	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Nickel (Ni) Selenium (Se)	GWh On or after July 6, 2027: 1.3E0 lb/ TBtu or 1.7E-2 lb/ GWh Before July 6, 2027: 3.5E0 lb/ TBtu or 4.0E-2 lb/ GWh On or after July 6, 2027: 1.2E0 lb/ TBtu or 1.3E-2 lb/ GWh Before July 6, 2027: 5.0E0 lb/ TBtu or 6.0E-2 lb/ GWh On or after	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	b. Hydrogen chloride (HCl) OR Sulfur dioxide (SO₂)⁴ c. Mercury (Hg)	July 6, 2027: 1.7E0 lb/ TBtu or 2.0E-2 lb/ GWh 2.0E-3 lb/ MMBtu or 2.0E-2 lb/ MWh 2.0E-1 lb/ MMBtu or 1.5E0 lb/ MWh 1.2E0 lb/ TBtu or 1.3E-2 lb/ GWh OR 1.0E0 lb/ TBtu or 1.1E-2 lb/	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. SO₂ CEMS. 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. 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

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM) OR Total non-Hg HAP metals	GWh Before July 6, 2027: 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh² On or after July 6, 2027: 1.0E-2 lb/MMBtu or 1.0E-1 lb/MWh² OR Before July 6, 2027: 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh On or after July 6, 2027:	Hg CEMS or sorbent trap monitoring system only. 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. On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 1 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	OR Individual HAP metals: Antimony (Sb) Arsenic (As)	1.7E-5 lb/MMBtu or 1.7E-1 lb/GWh OR Before July 6, 2027: 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh Before July 6, 2027:	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 3 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Beryllium (Be) Cadmium (Cd)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh On or after July 6, 2027: 3.7E-1 lb/TBtu or 6.7E-3 lb/GWh Before July 6, 2027: 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh On or after July 6, 2027: 6.7E-2 lb/TBtu or 6.7E-4 lb/GWh Before July 6, 2027: 3.0E-1 lb/TBtu or	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Chromium (Cr) Cobalt (Co)	3.0E-3 lb/GWh On or after July 6, 2027: 1.0E-1 lb/TBtu or 1.0E-3 lb/GWh Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E-2 lb/GWh On or after July 6, 2027: 9.3E-1 lb/TBtu or 1.0E-2 lb/GWh Before July 6, 2027: 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Lead (Pb)	On or after July 6, 2027: 2.7E-1 lb/ TBtu or 2.7E-3 lb/ GWh Before July 6, 2027: 1.2E0 lb/ TBtu or 2.0E-2 lb/ GWh	
	Manganese (Mn)	On or after July 6, 2027: 4.0E-1 lb/ TBtu or 6.7E-3 lb/ GWh Before July 6, 2027: 4.0E0 lb/ TBtu or 5.0E-2 lb/ GWh	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	b. Hydrogen chloride (HCl)	2.0E-2 lb/GWh 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	OR 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	Before July 6, 2027: 4.0E0 lb/TBtu or 4.0E-2 lb/GWh On or after July 6, 2027: 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 run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable	4.0E-2 lb/	Before July 6, 2027: Collect a minimum of 1 dscm

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	particulate matter (PM)	MMBtu or 4.0E-1 lb/MWh ²	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 Total non-Hg HAP metals	OR 6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals: Antimony (Sb)	OR 1.4E0 lb/TBtu or 2.0E-2 lb/GWh	Collect a minimum of 2 dscm per run.
	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	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . .
	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	2.2E+1 lb/	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	(Se)	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.
	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	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	8.0E-4 lb/MMBtu or	Collect a minimum of 1 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	OR Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd)	8.0E-3 lb/MWh OR 1.3E+1 lb/TBtu or 2.0E-1 lb/GWh 2.8E0 lb/TBtu or 3.0E-2 lb/GWh 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh 3.0E-1 lb/TBtu or 2.0E-3 lb/GWh	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 1 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Chromium (Cr)	GWh 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	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	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.
	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	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 2 dscm per run.
	Individual HAP metals:		
	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	3.0E-1 lb/	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	(Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se)	TBtu or 3.0E-3 lb/GWh 3.1E+1 lb/TBtu or 3.0E-1 lb/GWh 1.1E+2 lb/TBtu or 1.4E0 lb/GWh 4.9E0 lb/TBtu or 8.0E-2 lb/GWh 2.0E+1 lb/TBtu or 3.0E-1 lb/GWh 4.7E+2 lb/TBtu or 4.1E0 lb/GWh 9.8E0 lb/TBtu or	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
6. Solid oil-derived fuel-fired unit		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.
	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.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-	4.0E-5 lb/	Collect a minimum of 1 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Hg HAP metals OR Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd)	MMBtu or 6.0E-1 lb/GWh OR 8.0E-1 lb/TBtu or 7.0E-3 lb/GWh 3.0E-1 lb/TBtu or 5.0E-3 lb/GWh 6.0E-2 lb/TBtu or 5.0E-4 lb/GWh 3.0E-1 lb/TBtu or	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 3 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Chromium (Cr)	4.0E-3 lb/GWh 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	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit	b. Hydrogen chloride (HCl)	GWh 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	OR 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.
	a. Filterable particulate matter (PM)	Before July 6, 2027: 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh ² On or after July 6, 2027: 1.0E-2 lb/MMBtu or	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.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	OR Total non-Hg HAP metals OR Individual HAP	1.0E-1 lb/MWh² OR Before July 6, 2027: 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh On or after July 6, 2027: 1.7E-5 lb/MMBtu or 1.7E-1 lb/GWh OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 1 dscm per run. On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f). Collect a minimum of 3 dscm per run.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 (<i>e.g.</i> , specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	metals:		
	Antimony (Sb)	Before July 6, 2027: 8.0E-1 lb/ TBtu or 8.0E-3 lb/ GWh On or after July 6, 2027: 2.7E-1 lb/ TBtu or 2.7E-3 lb/ GWh	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/ TBtu or 2.0E-2 lb/ GWh On or after July 6, 2027: 3.7E-1 lb/ TBtu or 6.7E-3 lb/ GWh	
	Beryllium	Before July	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 (<i>e.g.</i>, specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	(Be)	6, 2027: 2.0E-1 lb/ TBtu or 2.0E-3 lb/ GWh On or after July 6, 2027:	
	Cadmium (Cd)	Before July 6, 2027: 3.0E-1 lb/ TBtu or 3.0E-3 lb/ GWh On or after July 6, 2027:	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ *Incorporated by reference, see § 63.14.*

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Cobalt (Co)	TBtu or 3.0E-2 lb/GWh On or after July 6, 2027: 9.3E-1 lb/TBtu or 1.0E-2 lb/GWh Before July 6, 2027: 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E-2 lb/	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Manganese (Mn)	GWh On or after July 6, 2027: 4.0E-1 lb/ TBtu or 6.7E-3 lb/ GWh Before July 6, 2027: 4.0E0 lb/ TBtu or 5.0E-2 lb/ GWh On or after July 6, 2027: 1.3E0 lb/ TBtu or 1.7E-2 lb/ GWh	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/ TBtu or 4.0E-2 lb/ GWh On or after	

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	Selenium (Se)	July 6, 2027: 1.2E0 lb/ TBtu or 1.3E-2 lb/ GWh Before July 6, 2027: 5.0E0 lb/ TBtu or 6.0E-2 lb/ GWh On or after July 6, 2027: 1.7E0 lb/ TBtu or 2.0E-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	6E-1 lb/ MMBtu or	SO ₂ CEMS.

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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

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 . . .
	(SO ₂) ⁴ c. Mercury (Hg) OR	9E0 lb/MWh 1.2E0 lb/TBtu or 1.3E-2 lb/GWh 1.0E0 lb/TBtu or 1.1E-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. 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. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

² Gross output.

³ Incorporated by reference, see § 63.14.

⁴ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

[85 FR 20850, Apr. 15, 2020, as amended at 89 FR 38571, May 7, 2024]

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

If your EGU is . . .	You must meet the following . . .
2. A new or reconstructed EGU 3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup	optimization software is employed, as specified in § 63.10021(e). 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). 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

If your EGU is . . .	You must meet the following . . .
	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-	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

If your EGU is . . .	You must meet the following . . .
derived fuel-fired EGU during shutdown	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:

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

If you demonstrate compliance using . . .	You must meet these operating limits . . .
	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]

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 and 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 MMBtu 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)).

		maintain the PM CEMS	
		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	Method 29 at appendix A-8 to part 60 of this

		each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	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	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	Method 4 at appendix A-3 to part 60 of this chapter.

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010 ³ with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 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 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% $\geq$ R $\leq$ 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: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100$
			(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,	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		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/MMBtu 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)).

		maintain the CEMS	
		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	Section 6 of appendix A to this subpart.

		emissions rates	
	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>i.e.</i> , 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	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). With the exception of IGCC units, on or after July 6, 2027: You may not use quarterly performance emissions testing to demonstrate compliance with the filterable PM emissions standards and for existing EGUs you may not choose to comply with the total or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

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]

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]

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

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
2. PM CPMS to measure compliance with a parametric operating limit. (On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.) 3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring 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. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations, unless it is for an IGCC unit.) 5. Conducting periodic performance tune-ups of your EGU(s) 6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup 7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	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. 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. If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan. Calculating the results of the testing in units of the applicable emissions standard. Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e). Operating in accordance with Table 3. Operating in accordance with Table 3.

[78 FR 24092, Apr. 24, 2013, as amended at 89 FR 38590, May 7, 2024]

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

You must submit the following reports . . .
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 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 40 CFR 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 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit).
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 40 CFR 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 the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(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 40 CFR 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 40 CFR 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 40 CFR 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.

You must submit the following reports . . .

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 (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 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 SO₂ CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 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 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 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 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.

11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format 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 40 CFR 63.10031(c)(5)(ii) and 40 CFR 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 40 CFR 63.10042 (see 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.

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 40 CFR 63.10031(g).

13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 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 Client Tool to submit the report, in a PDF file, no later than 60 days after that date.

You must submit the following reports . . .

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 (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 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]

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	No.

Citation	Subject	Applies to subpart UUUUU
	correct malfunctions ASAP	
§ 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.
§ 63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence	No.

Citation	Subject	Applies to subpart UUUUU
	and duration of startups and shutdowns	
§ 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	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.

Citation	Subject	Applies to subpart UUUUU
	actions	
§ 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 (Hg⁰, 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 Hg⁰ 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 ($\mu\text{g}/\text{dscm}$), 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.

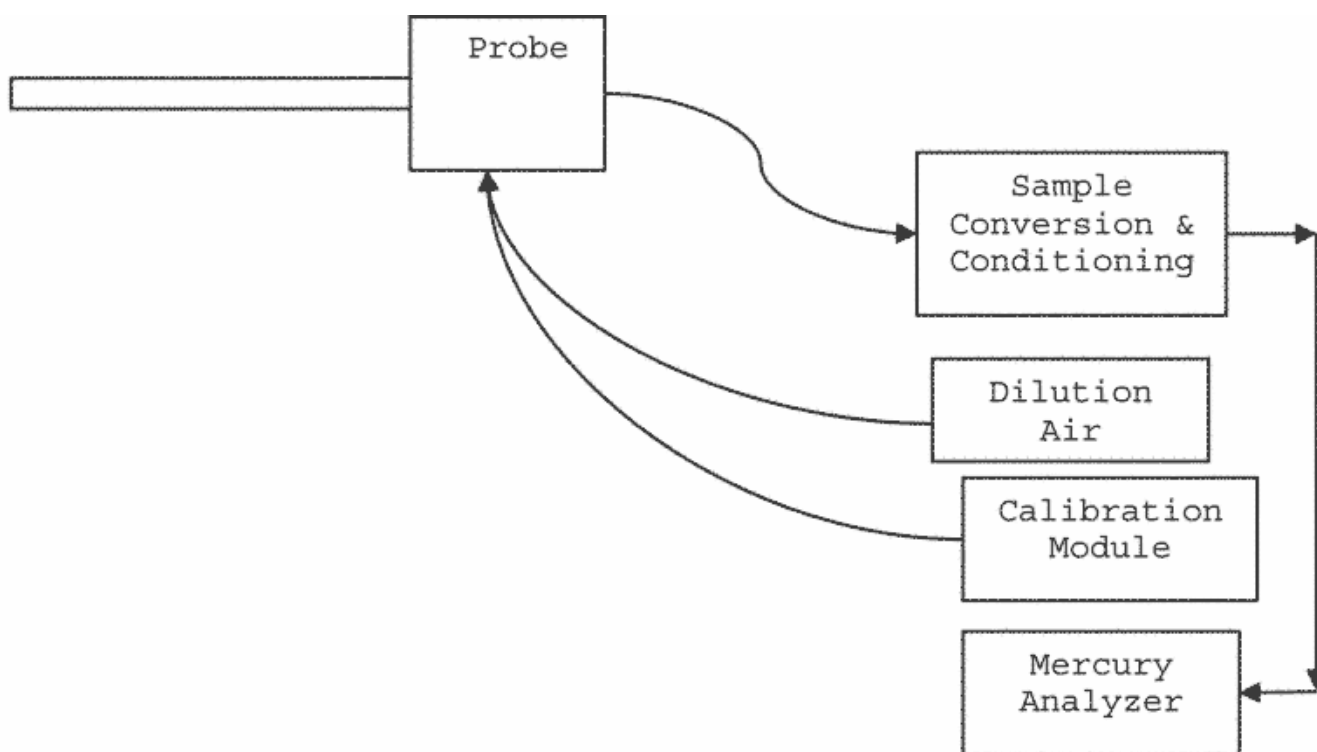


FIGURE A-1. TYPICAL MERCURY CEMS

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 HgCl₂ 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 $\mu\text{g}/\text{scm}$ for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 $\mu\text{g}/\text{scm}$. 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 CO₂ or O₂ 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 \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$ R - A \leq 1.0 \mu\text{g}/\text{scm}$	The alternate specification may be used on any day of the test.

¹ Note that $|R - A|$ is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{\text{avg}}|$ 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 $|RM_{\text{avg}} - C_{\text{avg}}|$ 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.

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 . . .
Linearity check ^{3 6}	$ R - A_{avg} \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$ R - A_{avg} \leq 0.8$ $\mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
3-level system integrity check ⁴	$ R - A_{avg} \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$ R - A_{avg} \leq 0.8$ $\mu\text{g}/\text{scm}$	The alternate specification may be used at any gas level.
RATA	20.0% RA	$ RM_{avg} - C_{avg} + CC \leq 0.5$ $\mu\text{g}/\text{scm}$ ⁷	$RM_{avg} < 2.5$ $\mu\text{g}/\text{scm}$
Cycle time test ⁵	15 minutes where the stability criteria are readings change by $< 2.0\%$ of span or by ≤ 0.5 $\mu\text{g}/\text{scm}$, 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.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (Eq. A - 1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples "a" and "b" (percent),

C_a = Hg concentration of Hg sample "a" (µg/dscm), and

C_b = Hg concentration of Hg sample "b" (µg/dscm).

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 $>1 \mu\text{g}/\text{dscm}$, $\leq 10\%$ of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations $\leq 1 \mu\text{g}/\text{dscm}$ and $>0.5 \mu\text{g}/\text{dscm}$, $\leq 20\%$ of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations $\leq 0.5 \mu\text{g}/\text{dscm}$ and $>0.1 \mu\text{g}/\text{dscm}$, $\leq 50\%$ of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations $\leq 0.1 \mu\text{g}/\text{dscm}$, 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 $\mu\text{g}/\text{scm}$ 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.*, combustng 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 \leq 5.0\%$ of span value or $ R - A \leq 1.0 \mu\text{g}/\text{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.

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . .	Acceptance criteria . . .
Single-level system integrity check	Weekly ¹	• Use oxidized Hg—either mid- or high-level	$ R - A_{avg} \leq 10.0\%$ of the reference gas value or $ R - A_{avg} \leq 0.8 \mu\text{g}/\text{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} \leq 10.0\%$ of the reference gas value, at each calibration gas level or $ R - A_{avg} \leq 0.8 \mu\text{g}/\text{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	$\leq 20.0\%$ RA or $ RM_{avg} - C_{avg} + CC \leq 0.5 \mu\text{g}/\text{scm}$, if $RM_{avg} < 2.5 \mu\text{g}/\text{scm}$.

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 $\mu\text{g}/\text{scm}$ 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:

$$M_h = K C_h Q_h \quad (\text{Equation A-2})$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/ μ g-scf,

C_h = Hourly average Hg concentration, wet basis (μ g/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(NOTE: Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \quad (\text{Equation A-3})$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/ μ g-scf.

C_h = Hourly average Hg concentration, dry basis (μ g/dscm).

Q_h = Stack gas volumetric flow rate for the hour (scfh)

(NOTE: Use unadjusted flow rate values; bias adjustment is not required).

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H₂O/100)

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.

$$E_{ho} = \frac{M_h}{(MW)_h} \times 10^3 \quad (\text{Equation A-4})$$

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

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.

$$\bar{E}_o = \frac{\sum_{h=1}^n E_{ho}}{n} \quad (\text{Eq. A - 5})$$

Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh),

E_{ho} = Gross output-based hourly Hg emission rate for unit or stack sampling hour “h” in the averaging period, from Equation A-4 of this appendix (lb/GWh), and

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. (NOTE: Do *not* INCLUDE NON-OPERATING HOURS WITH ZERO EMISSION RATES IN THE AVERAGE).

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 Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of 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 ($\mu\text{g}/\text{scm}$, 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 ($\mu\text{g}/\text{scm}$, 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 O₂) 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 CO₂ or O₂ 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 CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO₂ or O₂ 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 Client 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 Client 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 Client Tool to submit electronic quarterly reports to the Administrator, in an XML 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]

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 $70\% \leq R \leq 130\%$; 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:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \times 100 \quad (\text{Eq. B-1})$$

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 Client 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 CO₂ or O₂ 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 CO₂ or O₂ 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 CO₂ or O₂ 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 Client 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 Client 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 Client Tool to submit electronic quarterly reports to the Administrator in an XML 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]

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. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS-11, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

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. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in Procedure 2, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

- 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, CO₂ or O₂ 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, CO₂, O₂, 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 CO₂ or O₂ 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. However, if you have developed and are using a correlation curve, you may continue to use that curve, provided it continues to meet the acceptance criteria in PS-11 and Procedure 2 as discussed below. 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 Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS-11 and Procedure 2 the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.
- 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 (CO₂ or O₂) 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 Beginning on July 6, 2027 you must use the value of 0.015 lb/MMBtu in place of the applicable emission standard, or emission limit, in the calculations when determining if your PM CEMS meets the acceptance criteria in PS-11 and Procedure 2.

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. However, beginning on July 6, 2027 a value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, when determining whether the RCA and RRA are acceptable.
- 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, CO₂, O₂, 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, CO₂ concentration, O₂ 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:

$$C_{std} = C_a \left(\frac{460 + T_s}{P_s} \right) \left(\frac{P_{std}}{460 + T_{std}} \right) \quad (\text{Eq. C-1})$$

or

$$C_{std} = C_a \left(\frac{460 + T_{CEMS}}{P_{CEMS}} \right) \left(\frac{P_{std}}{460 + T_{std}} \right) \quad (\text{Eq. C-2})$$

Where:

C_{std} = PM concentration at standard conditions

C_a = PM concentration at measurement conditions

T_s = Stack Temperature (°F)

T_{CEMS} = CEMS Measurement Temperature (°F)

P_{CEMS} = CEMS Measurement Pressure (in. Hg)

P_s = Stack Pressure (in. Hg)

T_{std} = Standard Temperature (68 °F)

P_{std} = Standard Pressure (29.92 in. Hg).

6.2.2 Heat Input-Based PM Emission Rates (Existing EGUs, Only). Calculate the hourly heat input-based PM emission rates (if applicable), in units of lb/MMBtu, according to sections 6.2.2.1 and 6.2.2.2 of this appendix.

6.2.2.1 You must select an appropriate emission rate equation from among Equations 19-1 through 19-9 in appendix A-7 to part 60 of this chapter to convert the hourly PM concentration values from section 6.2.1 of this appendix to units of lb/MMBtu. Note that the EPA test Method 19 equations require the pollutant concentration to be expressed in units of lb/scf; therefore, you must first multiply the PM concentration by 6.24×10^{-8} to convert it from mg/scm to lb/scf.

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:

$$E_{heo} = 6.24 \times 10^{-8} \left(\frac{C_{std} Q_s}{MW} \right) \quad (\text{Eq. C-3})$$

Where:

E_{heo} = Hourly gross output-based PM emission rate (lb/MWh)

C_{std} = PM concentration from section 6.2.1 (mg/scm), wet basis

Q_s = Unadjusted stack gas volumetric flow rate (scfh, wet basis)

MW = Gross output (megawatts)

6.24×10^{-8} = Conversion factor

or

$$E_{heo} = 6.24 \times 10^{-8} \left(\frac{C_{std} Q_s}{MW} \right) (1 - B_{ws}) \quad (\text{Eq. C-4})$$

Where:

E_{heo} = Hourly gross output-based PM emission rate (lb/MWh)

C_{std} = PM concentration from section 6.2.1 (mg/scm), dry basis

Q_s = Unadjusted stack gas volumetric flow rate (scfh, wet basis)

MW = Gross output (megawatts)

B_{ws} = Proportion by volume of water vapor in the stack gas

6.24×10^{-8} = Conversion factor

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); and appropriate default values. Your electronic monitoring plan shall be evaluated and submitted using the ECMPS Client Tool provided by the Clean Air Markets Division (CAMD) in EPA's Office of Atmospheric Programs.

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 SO₂, CO₂, O₂ 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 (CO₂ or O₂) 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 CO₂ or O₂ 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 CO₂ or O₂ 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, CO₂ concentration, O₂ 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 Client 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 Client 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 Client Tool to submit electronic quarterly emissions reports to the Administrator, in an XML 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]

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, unless it is for an IGCC unit.

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 40 CFR 63.10000(d), you must use the ECMPS Client 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 SO₂, CO₂, O₂ 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 Client 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 Client Tool to submit electronic quarterly reports to the Administrator, in an XML 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 Client Tool to report the results of all performance stack tests conducted to document compliance with the applicable emissions limit in Table 1 or Table 2 to this subpart, as follows:

3.2.5.1 Report a summary of each test electronically, in XML format, in the relevant quarterly compliance report under 40 CFR 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]

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 40 CFR 63.10031(g), in an XML format prescribed 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, CO₂ or O₂ 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 SO₂ 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 Client Tool to report the test results as required under appendix A, B, or C to this subpart or, for SO₂ 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, 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, 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, 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, 26A, or 29 is used, you must still use EPA test Method 2 to determine the average stack gas velocity (v_s), 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 (CO₂ or O₂) concentration is required for each test run in which EPA test Method 5, 5D, 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 CO₂ or O₂ 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 SO₂ 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, 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 and 5D. The EPA test Method 5 (or, if applicable 5D) 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 SO₂ emissions from your coal-fired EGU as a surrogate for HCl, the SO₂ 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 SO₂ 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 40 CFR 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, 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 Client 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, 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, 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 (19.1, 19.3 through 19.30, and 19.38 through 19.41), 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 O₂;

19.16 Percent CO₂;

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, 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, 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 O₂;

22.18 Percent CO₂;

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 O₂;

24.14 Percent CO₂;

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 SO₂ RATA using instrumental EPA test Method 6C, and for each instrumental EPA test Method 3A O₂ or CO₂ 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 SO₂ 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 XML data file described in this appendix with supporting documentation, in a PDF file submitted concurrently with the XML file, such that all the data required to be reported by 40 CFR 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 40 CFR 63.10031(f)(6)(i) through (xii) of this section must be entered into ECMPS with each PDF submittal; the test number(s) (see 40 CFR 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]

Appendix J

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*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 63 —National Emission Standards for Hazardous Air Pollutants for Source Categories

Authority: 42 U.S.C. 7401 *et seq.*

Source: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

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- § 63.7490 What is the affected source of this subpart?
- § 63.7491 Are any boilers or process heaters not subject to this subpart?
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Alternative Emission Limits for New or Reconstructed Boilers
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2013

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Alternative Emission Limits for New or Reconstructed Boilers
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Alternative Emission Limits for Existing Boilers and Process
Heaters ^d

**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.

Equation 1a to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (Eq. 1a)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, *i*, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

Equation 1b to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (Eq. 1b)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, *Eadj*, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, *i*, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

Equation 1c to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (Eq. 1c)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, *Eadj*, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, *i*, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

- (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.

Equation 2 to paragraph (e)(2)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sm \times Cfi) \div \sum_{i=1}^n (Sm \times Cfi) \quad (Eq. 2)$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, *i*, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, *i*, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, *i*.

1.1 = Required discount factor.

- (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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (Eq. 3a)$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 3b})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 3c})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury

or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

E_o = The electric generating output for that calendar month from unit, i , in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

- (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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (\text{Eq. 4})$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i , in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i , in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i .

1.1 = Required discount factor.

- (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.

$$E_{avg} = \sum_{i=1}^n ER_i \div 12 \quad (\text{Eq. 5})$$

Where:

E_{avg} = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

- (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).

Equation 6 to paragraph (j)(1)

$$En = \sum_{i=1}^n (ELi \times Hi) \div \sum_{i=1}^n Hi \quad (\text{Eq. 6})$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

ELi = Appropriate emission limit from Table 2 or 15 to this subpart for unit i , in units of lb/MMBtu or ppm.

Hi = Heat input from unit i , MMBtu.

- (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.

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§ 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 (O₂) (or carbon dioxide (CO₂)) according to the procedures in paragraphs (a)(1) through (6) of this section.
 - (1) Install the CO CEMS including an O₂ (or CO₂) analyzer by the compliance date specified in § 63.7495. The CO and O₂ (or CO₂) 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 CO₂ analyzer as the diluent monitor. If a CO₂ 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 O₂ using the measured CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ is used to correct CO emissions and CO₂ 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 O₂ 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 O₂ 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 CO₂) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO₂) data concurrently. Collect at least four CO and oxygen (or CO₂) 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 CO₂ 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 your 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 (SO₂) 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 SO₂ 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 SO₂ CEMS must be installed by the compliance date specified in § 63.7495.
 - (2) For on-going quality assurance (QA), the SO₂ 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 SO₂ 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 SO₂ data, you must operate the SO₂ 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 SO₂ 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 SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values.

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§ 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 (Q_i) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (C_i).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^n (C_i \times Q_i) \quad (\text{Eq. 7})$$

Where:

$Clinput$ = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

C_i = Arithmetic average concentration of chlorine in fuel type, i , analyzed according to § 63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(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 (Q_i) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HG_i).
- (iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$\text{Mercuryinput} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Eq. 8})$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HG_i = Arithmetic average concentration of mercury in fuel type, i , analyzed according to § 63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

- (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 (Q_i) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSM_i).
 - (iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^n (TSM_i \times Q_i) \quad (\text{Eq. 9})$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSM_i = Arithmetic average concentration of TSM in fuel type, i , analyzed according to § 63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

- (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 milliamperes.
 - (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.

$$\bar{X} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{Y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

- (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.

$$R = \frac{Y_1}{(X_1 - z)} \quad (\text{Eq. 11})$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

- (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.

$$O_1 = z + \frac{0.75(L)}{R} \quad (\text{Eq. 12})$$

Where:

O_1 = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

- (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.

$$O_n = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

- (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.

$$30\text{-day} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 14})$$

Where:

30-day = 30-day average.

$Hpvi$ = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

- (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 SO₂ CEMS is to install and operate the SO₂ according to the requirements in § 63.7525(m) establish a maximum SO₂ emission rate equal to the highest hourly average SO₂ 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.

$$P90 = mean + (SD \times t) \quad (\text{Eq. 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

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

- (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.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 16})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

- (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.

$$Mercury = \sum_{i=1}^n (Hgi90 \times Qi) \quad (\text{Eq. 17})$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

- (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.

$$Metals = \sum_{i=1}^n (TSM_{90i} \times Q_i) \quad (\text{Eq. 18})$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSM_{i90} = 90th percentile confidence level concentration of TSM in fuel, i , in units of pounds per million Btu as calculated according to Equation 15 of this section.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(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 SO₂ 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 SO₂ 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 SO₂ operating limit by collecting the maximum hourly SO₂ emission rate on the SO₂ CEMS during the paired 3-run test for HCl. The maximum SO₂ operating limit is equal to the highest hourly average SO₂ 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:

$$ECredits = \left(\sum_{i=1}^n EIS_{iactual} \right) \div EI_{baseline} \quad (Eq. 19)$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(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.

Equation 20 to paragraph (f)

$$E_{adj} = E_m \times (1 - ECredits) \quad (Eq. 20)$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 to paragraph (c)(3)(i) of this section for the affected boiler.

- (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.

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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, SO₂, 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 of 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 C₃H₈.

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.

Equation 1 to the definition *Steam Output*

$$SO_M = S_1 + S_2 + (MW_{(3)} \times CFn) \quad (\text{Eq. 1})$$

Where:

SO_M = Total steam output for multi-function boiler, MMBtu.

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu.

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to paragraph (2) of this definition, MMBtu.

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh.

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh.

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8.

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7.

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1.

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2.

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2.

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.	8.0E-07 ^a lb per MMBtu	8.7E-07 ^a lb per	For M29, collect a

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
	Mercury	of heat input	MMBtu of steam output or 1.1E-05 ^a lb per MWh	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	a. Carbon	130 ppm by volume on a	0.11 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
coal boilers designed to burn coal/ solid fossil fuel	monoxide (CO) (or CEMS)	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)	MMBtu of steam output or 1.4 lb per MWh; 3-run average	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	a. CO (or	130 ppm by volume on a	0.11 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
bed units designed to burn coal/solid fossil fuel	CEMS)	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)	MMBtu of steam output or 1.4 lb per MWh; 3-run average	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.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
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.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
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	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to	1.3E-01 lb per MMBtu of steam	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	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) 4.1E-03 lb per MMBtu of heat input; or (8.4E-06 ^a lb per MMBtu of heat input)	output or 1.5 lb per MWh; 3-run average 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	a. CO (or CEMS)	220 ppm by volume on a dry basis corrected to	0.18 lb per MMBtu of steam	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
burners designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	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) 3.0E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	output or 2.5 lb per MWh; 3-run average 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	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to	3.5E-01 lb per MMBtu of steam	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
burners designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	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) 2.5E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	output or 3.6 lb per MWh; 3-run average 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	a. CO	910 ppm by volume on a dry basis corrected to	1.1 lb per MMBtu of steam output	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	3-percent oxygen 1.1E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	or 1.0E+01 lb per MWh 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	a. CO (or CEMS)	180 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by	0.22 lb per MMBtu of steam output or 2.0 lb per MWh; 3-run	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
burn biomass/bio-based solids	b. Filterable PM (or TSM)	volume on a dry basis corrected to 3-percent oxygen ^d , 30-day rolling average) 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	average 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

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
15. Units designed to burn heavy liquid fuel	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	per run. 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.
	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	1.9E-03 lb per MMBtu of heat input; or (6.1E-06 ^a	2.1E-03 lb per MMBtu of steam	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 CO₂ 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 CO₂ 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 CO₂ 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).

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
16. Units designed to burn light liquid fuel	PM (or TSM)	lb per MMBtu of heat input)	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)	
	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	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 CO₂ 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 CO₂ 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 CO₂ 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).

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
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	output or 4.0E-04 lb per MWh) 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	Collect a minimum of 4 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 CO₂ 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 CO₂ 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 CO₂ 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).

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
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	lb per MWh) 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

^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 CO₂ 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 CO₂ 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 CO₂ 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).

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
	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)	D6784 ^b collect a minimum of 3 dscm. 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 CO₂ 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 CO₂ 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 CO₂ 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
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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

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
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)	D6784 ^b collect a minimum of 3 dscm. 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/	a. CO (or	150 ppm by volume on a	0.14 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
others designed to burn coal/ solid fossil fuel	CEMS)	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)	MMBtu of steam output or 1.6 lb per MWh; 3-run average	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	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
exchanger designed to burn coal/ solid fossil fuel		volume on a dry basis corrected to 3-percent oxygen, ^c 30-day rolling average)	average	
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	Collect a minimum of 2 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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
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	output or 2.8E-03 lb per MWh) 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	a. CO (or CEMS)	210 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run	2.1E-01 lb per MMBtu of steam output or 2.3 lb	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
burn biomass/bio-based solid	b. Filterable PM (or TSM)	average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, ^c 30-day rolling average) 7.4E-03 lb per MMBtu of heat input; or (6.4E-05 lb per MMBtu of heat input)	per MWh; 3-run average 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-	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	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
based solid	b. Filterable PM (or TSM)	oxygen, ^c 10-day rolling average) 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.	1.8E-01 lb per MMBtu of	2.5E-01 lb per	Collect a minimum of 1

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
12. Fuel cell units designed to burn biomass/bio-based solid	Filterable PM (or TSM)	heat input; or (2.0E-03 lb per MMBtu of heat input)	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)	dscm per run.
	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	Collect a minimum of 2 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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
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)	output or 8.1E-02 lb per MWh) 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	a. HCl	1.1E-03 lb per MMBtu of	1.4E-03 lb per	For M26A, collect a

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
designed to burn liquid fuel	b.	heat input	MMBtu of steam output or 1.6E-02 lb per MWh	minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	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	5.9E-02 lb per MMBtu of heat input; or (2.0E-04 lb	7.2E-02 lb per MMBtu of steam	Collect a minimum of 1 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 CO₂ 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 CO₂ 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 CO₂ 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.

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	PM (or TSM)	per MMBtu of heat input)	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)	1 hr minimum sampling time. Collect a minimum of 3 dscm per run.
	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	
	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)	
17. Units	a. CO	130 ppm by volume on a	0.13 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
designed to burn liquid fuel that are non-continental units	b.	dry basis corrected to 3-percent oxygen, 3-run average based on stack test	MMBtu of steam output or 1.4 lb per MWh; 3-run average	time.
	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	2.9E-03 lb per	For M26A, collect a

^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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
		heat input	MMBtu of steam output or 1.8E-02 lb per MWh	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	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 CO₂ 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 CO₂ 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 CO₂ 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.

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 . . .
			lb per MWh)	

^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 CO₂ 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 CO₂ 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 CO₂ 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 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.
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	Must have a one-time energy assessment performed by a
^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).	

If your unit is . . .	You must meet the following . . .
located at a major source facility, not including limited use units	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

^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).

If your unit is . . .	You must meet the following . . .
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	efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments. 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).

^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).

If your unit is . . .	You must meet the following . . .
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	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. 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).
^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.	

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. . .
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (<i>i.e.</i>, 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. 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
^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.	

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. . .
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 b. Determine velocity and volumetric flow-rate of the stack gas c. Determine oxygen or carbon dioxide concentration of the stack gas d. Measure the moisture content of the stack gas e. Measure the PM emission	Method 1 at 40 CFR part 60, appendix A-1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter. 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 Method 4 at 40 CFR part 60, appendix A-3 of this chapter. Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of

^a Incorporated by reference, see § 63.14.

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
2. TSM	concentration	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.
	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.
3. Hydrogen chloride	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.
	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	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.

^a Incorporated by reference, see § 63.14.

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
4. Mercury	the stack gas	
	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.
	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
5. CO	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.
	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

^a Incorporated by reference, see § 63.14.

To conduct a performance test for the following pollutant . . .	You must . . .	Using, as appropriate . . .
	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.

^a Incorporated by reference, see § 63.14.

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
2. HCl	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.
	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.
3. Mercury Fuel Specification	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.
	a. Measure mercury concentration in the fuel sample and convert to	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

^a Incorporated by reference, see § 63.14.

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
for other gas 1 fuels	units of micrograms per cubic meter, 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^{ab}

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. Electrostatic precipitator operating parameters (option only)	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	(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. (a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15

^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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	for units that operate wet scrubbers)		during the PM or mercury performance test	minutes during the entire period of the performance tests.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(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. (a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (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

^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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
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	TSM) emission limitation. (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

^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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				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 §	(1) Data from the activated carbon rate monitors	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.

^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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
		63.7530(b)	and mercury performance test	(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

^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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
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	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. (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.

If you must meet the following operating limits or work practice standards . .	You must demonstrate continuous compliance by . . .
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 HCl, 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 SO₂ CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO₂ CEMS emission rate to a level at or below the highest hourly SO₂ rate measured during the HCl performance test according to § 63.7530.

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 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)	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).

[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

Citation	Subject	Applies to subpart DDDDD
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	alternative timeframe with the PM controls requirement in the startup work practice (2). 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.

Citation	Subject	Applies to subpart DDDDD
§ 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.

Citation	Subject	Applies to subpart DDDDD
§ 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,	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 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).	Availability of Information, Performance Track Provisions 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

^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 CO₂ 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 CO₂ 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).

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 . . .
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	minimum of 120 liters per run. 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	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.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
6. Stokers designed to burn coal/solid fossil fuel	CEMS) a. CO (or CEMS).	average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average) 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	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average) 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	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
solids		percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	
12. Suspension burners designed to burn biomass/bio-based solids	b. Filterable PM (or TSM) a. CO (or CEMS)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input) 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)	Collect a minimum of 3 dscm per run 1 hr minimum sampling time.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	b. Filterable PM (or TSM) a. CO (or CEMS)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) 1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run	Collect a minimum of 2 dscm per run. 1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
14. Fuel cell units designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen ^c 10-day rolling average)	Collect a minimum of 3 dscm per run.
	a. CO	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	910 ppm by volume on a dry basis corrected to 3 percent oxygen	Collect a minimum of 2 dscm per run.
	a. CO	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time.
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)	Collect a minimum of 3
	b.	2.6E-02 lb per MMBtu of	

^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 CO₂ 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 CO₂ 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).

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 . . .
16. Units designed to burn liquid fuel	Filterable PM (or TSM) a. HCl	heat input; or (4.4E-04 lb per MMBtu of heat input) 4.4E-04 lb per MMBtu of heat input	dscm per run 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	a. CO	130 ppm by volume on a	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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).

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 . . .
liquid fuel		dry basis corrected to 3 percent oxygen	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.	7.9E-06 lb per MMBtu of	For M29, collect a

^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 CO₂ 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 CO₂ 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).

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 . . .
	Mercury	heat input	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 CO₂ 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 CO₂ 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.

^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 CO₂ 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 CO₂ 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).

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 . . .
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.

^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 CO₂ 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 CO₂ 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).

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 . . .
8. Stokers/ sloped grate/ others designed to burn kiln-dried biomass fuel	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.
	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
9. Fluidized bed units designed to burn biomass/ bio-based solids	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.
	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.
10. Suspension burners	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.
	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent	1 hr minimum sampling time.

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^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 CO₂ 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 CO₂ 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).

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 . . .
designed to burn biomass/bio-based solids		oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	
	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	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.

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^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 CO₂ 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 CO₂ 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).

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 . . .
13. Hybrid suspension grate boiler designed to burn biomass/ bio-based solids	TSM)		
	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.
14. Units designed to burn liquid fuel	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.
	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.
15. Units designed to burn heavy liquid fuel	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.
	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b.	1.3E-02 lb per MMBtu of heat	Collect a minimum of 2 dscm

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^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 CO₂ 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 CO₂ 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).

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 . . .
	Filterable PM (or TSM)	input; or (7.5E-05 lb per MMBtu of heat input)	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	For M26A, Collect a minimum of

^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 CO₂ 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 CO₂ 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).

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 . . .
	c. Mercury	input 7.9E-06 lb per MMBtu of heat input	2 dscm per run; for M26, collect a minimum of 240 liters per run. 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 CO₂ 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 CO₂ 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 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 CO₂ 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 CO₂ 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).

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 . . .
3. 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.
	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	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	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
burn coal/solid fossil fuel		average)	
	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.

^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 CO₂ 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 CO₂ 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).

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 . . .
8. Fluidized bed units designed to burn biomass/bio-based solids	TSM)		
	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.
9. Suspension burners designed to burn biomass/bio-based solids	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.
	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.
10. Dutch Ovens/Pile burners designed to	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.
	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	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
burn biomass/ bio-based solids		3 percent oxygen, ^c 10-day rolling average)	
	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.

^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 CO₂ 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 CO₂ 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).

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 . . .
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 ^b collect 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.

^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 CO₂ 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 CO₂ 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).

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 . . .
16. Units designed to burn liquid fuel that are non-continental units	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.
	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.
17. Units designed to burn gas 2 (other) gases	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.
	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

^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 CO₂ 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 CO₂ 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).

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 . . .
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm. 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 CO₂ 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 CO₂ 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	8.7E-07 ^a lb per MMBtu of steam	For M29, collect a minimum of 4 dscm per

^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 CO₂ 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 CO₂ 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).

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 . . .
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)	output or 1.1E-05 ^a lb per MWh 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)	run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm. Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers	a. Carbon monoxide	130 ppm by volume on a dry basis corrected to	0.11 lb per MMBtu of steam	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
designed to burn coal/ solid fossil fuel	(CO) (or CEMS)	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)	output or 1.4 lb per MWh; 3-run average	
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	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to	0.11 lb per MMBtu of steam	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
designed to burn coal/ solid fossil fuel		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)	output or 1.4 lb per MWh; 3-run 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/	a. CO (or	620 ppm by volume on a	5.8E-01 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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).

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 . . .
sloped grate/ others designed to burn wet biomass fuel	CEMS)	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)	MMBtu of steam output or 6.8 lb per MWh; 3-run average	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/	a. CO	460 ppm by volume on a	4.2E-01 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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).

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 . . .
sloped grate/ others designed to burn kiln-dried biomass fuel	b. Filterable PM (or TSM)	dry basis corrected to 3-percent oxygen 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	MMBtu of steam output or 5.1 lb per MWh 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)	time. Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run	2.2E-01 lb per MMBtu of steam output or 2.6 lb	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
burn biomass/bio-based solids	b. Filterable PM (or TSM)	average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, ^d 30-day rolling average) 9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input)	per MWh; 3-run average 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	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run	1.9 lb per MMBtu of steam output or 27 lb per MWh;	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, ^d 10-day rolling average) 3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3-run average 3.1E-02 lb per MMBtu of steam output or 4.2E-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	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run	3.5E-01 lb per MMBtu of steam output or 3.6 lb	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
designed to burn biomass/bio-based solids	b. Filterable PM (or TSM)	average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, ^d 10-day rolling average) 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	per MWh; 3-run average 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	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	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
burn biomass/bio-based solids	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	MWh 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	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	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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).

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 . . .
biomass/bio-based solids	b. Filterable PM (or TSM)	corrected to 3-percent oxygen, ^d 30-day rolling average) 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.

^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 CO₂ 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 CO₂ 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).

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 . . .
15. Units designed to burn heavy liquid fuel	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.
	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	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 ^a lb per MMBtu of heat	1.5E-02 lb per MMBtu of steam output or 1.8E-01	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 CO₂ 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 CO₂ 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).

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 . . .
16. Units designed to burn light liquid fuel	TSM)	input)	lb per MWh; or (8.2E-05 ^a lb per MMBtu of steam output or 1.1E-03 ^a lb per MWh)	
	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	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 CO₂ 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 CO₂ 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).

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 . . .
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	lb per MWh) 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.

^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 CO₂ 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 CO₂ 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).

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 . . .
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

^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 CO₂ 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 CO₂ 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).

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 . . .
	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)	minimum of 3 dscm. 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 CO₂ 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 CO₂ 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

^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 CO₂ 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 CO₂ 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.

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 . . .
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)	D6784 ^b collect a minimum of 3 dscm. 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/	a. CO (or	160 ppm by volume on a	0.14 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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.

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 . . .
others designed to burn coal/ solid fossil fuel	CEMS)	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)	MMBtu of steam output or 1.7 lb per MWh; 3-run average	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	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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.

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 . . .
exchanger designed to burn coal/ solid fossil fuel		volume on a dry basis corrected to 3-percent oxygen, ^c 30-day rolling average)	average	
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	Collect a minimum of 2 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 CO₂ 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 CO₂ 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.

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 . . .
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	output or 3.4E-04 lb per MWh) 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	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run	4.6E-01 lb per MMBtu of steam output or 5.2 lb	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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.

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 . . .
burn biomass/bio-based solid	b. Filterable PM (or TSM)	average; or (310 ppm by volume on a dry basis corrected to 3- percent oxygen, ^c 30-day rolling average) 1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	per MWh; 3-run average 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-	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	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.

^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 CO₂ 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 CO₂ 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.

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 . . .
based solid	b. Filterable PM (or TSM)	oxygen, ^c 10-day rolling average) 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.	2.8E-01 lb per MMBtu of	3.9E-01 lb per	Collect a minimum of 1

^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 CO₂ 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 CO₂ 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.

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 . . .
12. Fuel cell units designed to burn biomass/bio-based solid	Filterable PM (or TSM)	heat input; or (2.0E-03 lb per MMBtu of heat input)	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)	dscm per run.
	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	Collect a minimum of 2 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 CO₂ 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 CO₂ 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.

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 . . .
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)	output or 8.1E-02 lb per MWh) 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	a. HCl	1.1E-03 lb per MMBtu of	1.4E-03 lb per	For M26A, collect a

^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 CO₂ 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 CO₂ 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.

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 . . .
designed to burn liquid fuel	b. Mercury	heat input 2.0E-06 lb per MMBtu of heat input	MMBtu of steam output or 1.6E-02 lb per MWh 2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. 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	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb	7.5E-02 lb per MMBtu of steam	Collect a minimum of 1 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 CO₂ 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 CO₂ 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.

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	PM (or TSM)	per MMBtu of heat input)	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)	1 hr minimum sampling time. Collect a minimum of 3 dscm per run.
	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	
	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)	
17. Units	a. CO	130 ppm by volume on a	0.13 lb per	1 hr minimum sampling

^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 CO₂ 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 CO₂ 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.

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 . . .
designed to burn liquid fuel that are non-continental units	b. Filterable PM (or TSM)	dry basis corrected to 3-percent oxygen, 3-run average based on stack test	MMBtu of steam output or 1.4 lb per MWh; 3-run average	time.
18. Units designed to burn gas 2 (other) gases	a. CO	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.
	b. HCl	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.
		1.7E-03 lb per MMBtu of	2.9E-03 lb per	For M26A, collect a

^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 CO₂ 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 CO₂ 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.

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 . . .
		heat input	MMBtu of steam output or 1.8E-02 lb per MWh	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	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.

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^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 CO₂ 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 CO₂ 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.

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 . . .
			lb per MWh)	

^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 CO₂ 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 CO₂ 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 C.F.R. § 60, Subpart JJJJ - *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

What This Subpart Covers

§ 60.4230 Am I subject to this subpart?

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§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

§ 60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

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§ 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

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§ 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

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§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?

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§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

§ 60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

Compliance Requirements for Owners and Operators

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

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§ 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

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§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

General Provisions

§ 60.4246 What General Provisions and confidential information provisions apply to me?

Mobile Source Provisions

§ 60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

Definitions

§ 60.4248 What definitions apply to this subpart?

Table 1 to Subpart JJJJ of Part 60

NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Table 2 to Subpart JJJJ of Part 60

Requirements for Performance Tests

Table 3 to Subpart JJJJ of Part 60

Applicability of General Provisions to Subpart JJJJ

Table 4 to Subpart JJJJ of Part 60

Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

Source: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 60.4230 Am I subject to this subpart?

- (a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) 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 SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.
 - (2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:
 - (i) On or after July 1, 2008; or
 - (ii) On or after January 1, 2009, for emergency engines.
 - (3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:
 - (i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
 - (ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;
 - (iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or
 - (iv) On or after January 1, 2009, for emergency engines.
 - (4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:
 - (i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
 - (ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;
 - (iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

- (iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).
- (5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.
- (6) The provisions of § 60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.
- (b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine 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 as applicable.
- (d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.
- (e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 1048 and 1054, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.
- (f) Owners and operators of facilities with internal combustion engines 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.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37972, June 28, 2011; 86 FR 34360, June 29, 2021]

EMISSION STANDARDS FOR MANUFACTURERS

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

- (a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, as follows:

If engine displacement is . . .	and manufacturing dates are . . .	the engine must meet the following non-handheld emission standards identified in 40 CFR part 1054 and related requirements:
(1) Below 225	July 1, 2008 to	Phase 2.

If engine displacement is . . .	and manufacturing dates are . . .	the engine must meet the following non-handheld emission standards identified in 40 CFR part 1054 and related requirements:
cc	December 31, 2011	
(2) Below 225 cc	January 1, 2012 or later	Phase 3.
(3) At or above 225 cc	July 1, 2008 to December 31, 2010	Phase 2.
(4) At or above 225 cc	January 1, 2011 or later	Phase 3.

- (b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.
- (c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.

- (d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.
- (e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.
- (f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.
- (g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI 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 SI ICE.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59175, Oct. 8, 2008; 76 FR 37973, June 28, 2011; 78 FR 6697, Jan. 30, 2013; 86 FR 34360, June 29, 2021]

§ 60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in § 60.4231 during the certified emissions life of the engines.

EMISSION STANDARDS FOR OWNERS AND OPERATORS

§ 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

- (a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in § 60.4231(a) for their stationary SI ICE.
- (b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that use gasoline must comply with the emission standards in § 60.4231(b) for their stationary SI ICE.
- (c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in § 60.4231(c) for their stationary SI ICE.
- (d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.
- (e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.
- (f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.
 - (1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in § 60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in § 60.4231(a) applicable to engines manufactured on July 1, 2008.

- (2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission standards in § 60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).
- (3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in § 60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).
- (4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_x) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO_x emission standard of 250 ppmvd at 15 percent oxygen (O₂), a CO emission standard 540 ppmvd at 15 percent O₂ (675 ppmvd at 15 percent O₂ for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O₂, where the date of manufacture of the engine is:
 - (i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
 - (ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;
 - (iii) Prior to January 1, 2009, for emergency engines;
 - (iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.
- (5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply

with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

- (g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.
- (h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37973, June 28, 2011]

§ 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in § 60.4233 over the entire life of the engine.

OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 1090.205.

[73 FR 3591, Jan. 18, 2008, as amended at 85 FR 78463, Dec. 4, 2020]

§ 60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

- (a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in § 60.4233.
- (b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in § 60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in § 60.4233 may not be installed after January 1, 2010.
- (c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in § 60.4233 after January 1, 2011.

- (d) In addition to the requirements specified in §§ 60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.
- (e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

- (a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.
- (c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

COMPLIANCE REQUIREMENTS FOR MANUFACTURERS

§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(a) must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[86 FR 34361, June 29, 2021]

§ 60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part

1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[86 FR 34361, June 29, 2021]

§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[86 FR 34361, June 29, 2021]

§ 60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

- (a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in § 60.4247. Manufacturers of stationary SI internal combustion engines who choose not to certify their engines under this section must notify the ultimate purchaser that testing requirements apply as described in § 60.4243(b)(2); manufacturers must keep a copy of this notification for five years after shipping each engine and make those documents available to EPA upon request.
- (b) Manufacturers of engines other than those certified to standards in 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to Large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization for Standardization 8178-4: 1996(E) (incorporated by reference, see § 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Manufacturers of any size may certify their stationary emergency engines at or above 130 hp using assigned deterioration factors established by

EPA, consistent with 40 CFR 1048.240. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

- (c) Certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.
- (d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in § 60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.
- (e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.
- (f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in § 60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.
- (g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in § 60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).
- (h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.
- (i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR part 1065, subpart C, to determine the total NMHC emissions. As an alternative, manufacturers may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59176, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 86 FR 34361, June 29, 2021]

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

- (a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR parts 1048, 1054, and 1068, as applicable, except that engines certified pursuant to the voluntary certification procedures in § 60.4241 are subject only to the provisions indicated in § 60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of § 60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.
- (b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards identified in 40 CFR part 1048 or 1054 for that model year may certify any such family that contains both nonroad 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. This paragraph (b) also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.
- (c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words "and stationary" after the word "nonroad" to the label.
- (d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).
- (e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled and exported according to 40 CFR 1068.230. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.
- (f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:
 - (1) The engines must be equipped with non-resettable hour meters.

- (2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.
- (3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

[86 FR 34362, June 29, 2021]

COMPLIANCE REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

- (a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in § 60.4233(a) through (c), you must comply 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, you must meet one of the requirements specified in (a)(1) and (2) of this section.
 - (1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.
 - (2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.
 - (i) If you are an owner or operator of a stationary SI internal combustion engine 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, but no performance testing is required if you are an owner or operator.
 - (ii) If you are an owner or operator of a stationary SI 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 within 1 year of engine startup to demonstrate compliance.
 - (iii) If you are an owner or operator of a stationary SI 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 within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

- (b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.
 - (1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.
 - (2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in § 60.4233(d) or (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.
 - (i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 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.
 - (ii) If you are an owner or operator of a stationary SI 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 and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.
- (c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in § 60.4233(f).
- (d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(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 (d)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(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 (d)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(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 (d)(2) of this section. Except as provided in paragraph (d)(3)(i) 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) 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]

- (e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of § 60.4233.
- (f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this

section, but you are not required to conduct subsequent performance testing unless the stationary engine undergoes rebuild, major repair or maintenance. Engine rebuilding means to overhaul an engine or to otherwise perform extensive service on the engine (or on a portion of the engine or engine system). For the purpose of this paragraph (f), perform extensive service means to disassemble the engine (or portion of the engine or engine system), inspect and/or replace many of the parts, and reassemble the engine (or portion of the engine or engine system) in such a manner that significantly increases the service life of the resultant engine.

- (g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.
- (h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.
 - (1) Purchasing an engine certified according to 40 CFR part 1048. 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.
- (i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.
 - (1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4233(f), as applicable.
 - (2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37974, June 28, 2011; 78 FR 6697, Jan. 30, 2013; 86 FR 34362, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

- (a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Table 2 to this subpart.
- (b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.
- (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 be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.
- (d) 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 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-1} \times Q \times T}{HP - hr} \quad (Eq. 1)$$

Where:

ER = Emission rate of NO_x in g/HP-hr.

C_d = Measured NO_x concentration in parts per million by volume (ppmv).

1.912 × 10⁻³ = Conversion constant for ppm NO_x to grams per standard cubic meter at 20 degrees Celsius.

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

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

- (e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-1} \times Q \times T}{HP - hr} \quad (Eq. 2)$$

Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164 × 10⁻³ = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

- (f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP-hr} \quad (Eq. 3)$$

Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

- (g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{vi}}{C_{Ai}} \quad (Eq. 4)$$

Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{Mi} = RF_i \times C_{Ai} \quad (Eq. 5)$$

Where:

$C_{i\text{corr}}$ = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

$C_{i\text{meas}}$ = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{\text{Peq}} = 0.6098 \times C_{i\text{corr}} \quad (\text{Eq. 6})$$

Where:

C_{Peq} = Concentration of compound i in mg of propane equivalent per DSCM.

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

- (a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.
 - (1) All notifications submitted to comply with this subpart and all documentation supporting any notification.
 - (2) Maintenance conducted on the engine.
 - (3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.
 - (4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to § 60.4243(a)(2), documentation that the engine meets the emission standards.
- (b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of 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.

- (c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in § 60.4231 must submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section. Beginning on February 26, 2025 submit the notification electronically according to paragraph (g) of this section.
 - (1) Name and address of the owner or operator;
 - (2) The address of the affected source;
 - (3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
 - (4) Emission control equipment; and
 - (5) Fuel used.
- (d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in § 60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference—see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7. Beginning on February 26, 2025, performance tests must be reported electronically according to paragraph (f) of this section.
- (e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(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 § 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(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.

- (f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test, you must submit the results following the procedures specified in paragraph (g) of this section. Data collected using test methods that are 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 an alternate electronic file.
- (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 Spark 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 Spark 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.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 78 FR 6697, Jan. 30, 2013; 81 FR 59809, Aug. 30, 2016; 86 FR 34362, June 29, 2021; 87 FR 48606, Aug. 10, 2022; 89 FR 70514, Aug. 30, 2024]

GENERAL PROVISIONS

§ 60.4246 What General Provisions and confidential information provisions apply to me?

- (a) Table 3 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]

MOBILE SOURCE PROVISIONS

§ 60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

- (a) Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Note that 40 CFR part 1054, appendix I, describes various provisions that do not apply for engines meeting Phase 1 standards in 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.
- (b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048 pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

- (c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 86 FR 34362, June 29, 2021]

DEFINITIONS

§ 60.4248 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 1054.107 and 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

- (1) 1,000 hours of operation.
- (2) Your recommended overhaul interval.
- (3) Your mechanical warranty for the engine.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 1048 or 1054, as appropriate.

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.

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 carbon dioxide (CO₂).

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 § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), 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 § 60.4243(d).
- (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 § 60.4243(d)(3)(i).

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

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.

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

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.

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

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 CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air 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 resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

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").

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.

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.

Pipeline-quality 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, and which is provided by a supplier through a pipeline. Pipeline-quality 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 British thermal units per standard cubic foot.

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 June 12, 2006, 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.

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 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 compression ignition 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.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in 40 CFR part 63, subpart P, that tests stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

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.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 78 FR 6698, Jan. 30, 2013; 86 FR 34363, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart JJJJ of Part 60—NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards ^a					
			g/HP-hr			ppmvd at 15% O ₂		
			NO _x	CO	VOC ^d	NO _x	CO	VOC ^d
Non-Emergency SI Natural Gas ^b and Non-Emergency SI Lean Burn LPG ^b	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25<HP<130	1/1/2009	^c 10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

^a Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O₂.

^b Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

^c The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_x + HC.

^d For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

[76 FR 37975, June 28, 2011]

Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244	a. Limit the concentration of NO _x in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/ location of traverse points at the exhaust of the stationary internal combustion engine; ii. Determine the O₂	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate (2) Method 3, 3A, or 3B^b of	(a) Alternatively, for NO_x, O₂, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, 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. (b) Measurements to determine O₂ concentration must be made at the

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
		concentration of the stationary internal combustion engine exhaust at the sampling port location; iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust; iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location;	40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) ^{a d} (3) Method 2 or 2C of 40 CFR part 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7 (4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{d e}	same time as the measurements for NO _x concentration. (c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO _x concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable. (d) Measurements to determine moisture must be made at the same time as the measurement for NO _x concentration.

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
		and v. 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	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005), ^{a d} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{d e}	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/ location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, 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 <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60,

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Determine the O₂ concentration of the stationary internal combustion engine exhaust at the sampling port location; iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust; iv. If necessary, measure	(2) Method 3, 3A, or 3B^b of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005)^{a d} (3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7 (4) Method 4 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. (b) Measurements to determine O₂ concentration must be made at the same time as the measurements for CO concentration. (c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable. (d) Measurements to determine moisture must be made at the same time as the measurement for

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
	combustion engine exhaust	location of traverse points at the exhaust of the stationary internal combustion engine;	flow rate	inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, 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. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B ^b of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) ^{a d}	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust	(3) Method 2 or 2C of 40 CFR 60, appendix A-1	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
		flowrate of the stationary internal combustion engine exhaust; iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be	or Method 19 of 40 CFR part 60, appendix A-7 (4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,^e or ASTM Method D6348-03^{d e} (5) Methods 25A and 18 of 40 CFR part 60, appendices A-6 and A-7, Method 25A with the use of a hydrocarbon cutter as described in	concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable. (d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration. (e) Results of this test consist of the average of the three 1-hour or longer runs.

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

For each	Complying with the requirement to	You must	Using	According to the following requirements
		located at the outlet of the control device	40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6, ^{c e} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{d e}	

^a Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^b You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^c You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^d Incorporated by reference; see 40 CFR 60.17.

^e You must meet the requirements in § 60.4245(d).

[85 FR 63408, Oct. 7, 2020]

Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

[AS STATED IN § 60.4246, 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	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4248.
§ 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 § 60.4245.
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§ 60.9	Availability of information	Yes	Requirements are specified in subpart JJJJ.
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	Yes	
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	No	
§ 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	

Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[AS STATED IN § 60.4247, YOU MUST COMPLY WITH THE FOLLOWING APPLICABLE MOBILE SOURCE PROVISIONS IF YOU ARE A MANUFACTURER PARTICIPATING IN THE VOLUNTARY CERTIFICATION PROGRAM AND CERTIFYING STATIONARY SI ICE TO EMISSION STANDARDS IN TABLE 1 OF SUBPART JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	Except for the specific sections below.
1048 subpart B	Emission Standards and Related Requirements	Yes	
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	Except for the specific sections below.
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I	Yes		

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
and II			
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.
1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

Appendix L

40 C.F.R. § 97, Subpart BBBBBB —*TR NO_x Ozone Season Trading Program*

This content is from the eCFR and is authoritative but unofficial.

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 97 —Federal NO_x Budget Trading Program, CAIR NO_x and SO₂ Trading Programs, CSAPR NO_x and SO₂ Trading Programs, and Texas SO₂ Trading Program

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, et seq.

Source: 65 FR 2727, Jan. 18, 2000, unless otherwise noted. 71 FR 25396, 25422, and 25443, Apr. 28, 2006

Subpart BBBBB CSAPR NO_x Ozone Season Group 1 Trading Program

§ 97.501 Purpose.

§ 97.502 Definitions.

§ 97.503 Measurements, abbreviations, and acronyms.

§ 97.504 Applicability.

§ 97.505 Retired unit exemption.

§ 97.506 Standard requirements.

§ 97.507 Computation of time.

§ 97.508 Administrative appeal procedures.

§ 97.509 [Reserved]

§ 97.510 State NO_x Ozone Season Group 1 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

§ 97.511 Timing requirements for CSAPR NO_x Ozone Season Group 1 allowance allocations.

§ 97.512 CSAPR NO_x Ozone Season Group 1 allowance allocations to new units.

§ 97.513 Authorization of designated representative and alternate designated representative.

§ 97.514 Responsibilities of designated representative and alternate designated representative.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

§ 97.516 Certificate of representation.

§ 97.517 Objections concerning designated representative and alternate designated representative.

§ 97.518 Delegation by designated representative and alternate designated representative.

§ 97.519 [Reserved]

§ 97.520 Establishment of compliance accounts, assurance accounts, and general accounts.

§ 97.521 Recordation of CSAPR NO_x Ozone Season Group 1 allowance allocations and auction results.

§ 97.522 Submission of CSAPR NO_x Ozone Season Group 1 allowance transfers.

§ 97.523 Recordation of CSAPR NO_x Ozone Season Group 1 allowance transfers.

§ 97.524 Compliance with CSAPR NO_x Ozone Season Group 1 emissions limitation.

§ 97.525 Compliance with CSAPR NO_x Ozone Season Group 1 assurance provisions.

§ 97.526 Banking and conversion.

§ 97.527 Account error.

§ 97.528 Administrator's action on submissions.

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

§ 97.531 Initial monitoring system certification and recertification procedures.

§ 97.532 Monitoring system out-of-control periods.

§ 97.533 Notifications concerning monitoring.

§ 97.534 Recordkeeping and reporting.

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

Subpart BBBBB—CSAPR NO_x Ozone Season Group 1 Trading Program

Source: 76 FR 48406, Aug. 8, 2011, unless otherwise noted.

Editorial Note: Nomenclature changes appear at 81 FR 74608, Oct. 26, 2016.

§ 97.501 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Cross-State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 1 Trading Program, under section 110 of the Clean Air Act and § 52.38 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74608, Oct. 26, 2016]

§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows, provided that any term that includes the acronym “CSAPR” shall be considered synonymous with a term that is used in a SIP revision approved by the Administrator under § 52.38 or § 52.39 of this chapter and that is substantively identical except for the inclusion of the acronym “TR” in place of the acronym “CSAPR”:

Acid Rain Program means a multi-state SO₂ and NO_x air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to CSAPR NO_x Ozone Season Group 1 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(3), (4), or (5) of this chapter, of the amount of such CSAPR NO_x Ozone Season Group 1 allowances to be initially credited, at no cost to the recipient, to:

- (1) A CSAPR NO_x Ozone Season Group 1 unit;
- (2) A new unit set-aside;
- (3) An Indian country new unit set-aside; or
- (4) An entity not listed in paragraphs (1) through (3) of this definition;
- (5) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_x Ozone Season Group 1 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_x Ozone Season Group 1 allowances, the CSAPR NO_x Ozone Season Group 1 unit will be treated as being allocated an amount (*i.e.*, zero) of CSAPR NO_x Ozone Season Group 1 allowances.

Allowance Management System means the system by which the Administrator records allocations, auctions, transfers, and deductions of CSAPR NO_x Ozone Season Group 1 allowances under the CSAPR NO_x Ozone Season Group 1 Trading Program. Such allowances are allocated, auctioned, recorded, held, transferred, or deducted only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, auction, holding, transfer, or deduction of CSAPR NO_x Ozone Season Group 1 allowances.

Allowance transfer deadline means, for a control period in 2015 or 2016, midnight of December 1 immediately after such control period or, for a control period in a year from 2017 through 2020, midnight of March 1 immediately after such control period or, for a control period in 2021 or thereafter, midnight of June 1 immediately after such control period (or if such December 1, March 1, or June 1 is not a business day, midnight of the first business day thereafter) and is the deadline by which a CSAPR NO_x Ozone Season Group 1 allowance transfer must be submitted for recordation in a CSAPR NO_x Ozone Season Group 1 source's compliance account in order to be available for use in complying with the source's CSAPR NO_x Ozone Season Group 1 emissions limitation for such control period in accordance with §§ 97.506 and 97.524.

Alternate designated representative means, for a CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CSAPR NO_x Ozone Season Group 1 Trading Program. If the CSAPR NO_x Ozone Season Group 1 source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR SO₂ Group 1 Trading Program, or CSAPR SO₂ Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under § 97.525(b)(3) for certain owners and operators of a group of one or more CSAPR NO_x Ozone Season Group 1 sources and units in a given State (and Indian country within the borders of such State), in which are held CSAPR NO_x Ozone Season Group 1 allowances available for use for a control period in a given year in complying with the CSAPR NO_x Ozone Season Group 1 assurance provisions in accordance with §§ 97.506 and 97.525.

Auction means, with regard to CSAPR NO_x Ozone Season Group 1 allowances, the sale to any person by a State or permitting authority, in accordance with a SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(4) or (5) of this chapter, of such CSAPR NO_x Ozone Season Group 1 allowances to be initially recorded in an Allowance Management System account.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CSAPR NO_x Ozone Season Group 1 allowances held in the general account and, for a CSAPR NO_x Ozone Season Group 1 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

- (1) Any organic material grown for the purpose of being converted to energy;
- (2) Any organic byproduct of agriculture that can be converted into energy; or
- (3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is:
 - (i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
 - (ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

- (1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;
- (2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or
- (3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means “coal” as defined in § 72.2 of this chapter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

- (1) Operating as part of a cogeneration system; and
- (2) Producing on an annual average basis—
 - (i) For a topping-cycle 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; or
 - (ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;
- (3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;
- (4) 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; and
- (5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

- (1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and
- (2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

- (1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.505.
 - (i) For a unit that is a CSAPR NO_x Ozone Season Group 1 unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.
 - (ii) For a unit that is a CSAPR NO_x Ozone Season Group 1 unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of

commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

- (2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.505, for a unit that is not a CSAPR NO_x Ozone Season Group 1 unit under § 97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CSAPR NO_x Ozone Season Group 1 unit under § 97.504.
- (i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.
- (ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such a control period before 2021, or as of July 1 immediately after such deadline for such a control period in 2021 or thereafter, the same natural person is authorized under §§ 97.513(a) and 97.515(a) as the designated representative for a group of one or more CSAPR NO_x Ozone Season Group 1 sources and units in a State (and Indian country within the borders of such State).

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii), the amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_x Ozone Season Group 1 allowances allocated for such control period to the group of one or more CSAPR NO_x Ozone Season Group 1 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_x Ozone Season Group 1 allowances purchased by an owner or operator of such CSAPR NO_x Ozone Season Group 1 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_x Ozone Season Group 1 units in accordance with the CSAPR NO_x Ozone Season Group 1 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(4) or (5) of this chapter, multiplied by the sum of the State NO_x Ozone Season Group 1 trading budget under § 97.510(a) and the State's variability limit under § 97.510(b) for such control period, and divided by such State NO_x Ozone Season Group 1 trading budget.

Common designated representative's share means, with regard to a specific common designated representative for a control period in a given year and a total amount of NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NO_x emissions during such control period from the group of one or more CSAPR NO_x Ozone Season Group 1 units in such State (and such Indian country) having the common designated representative for such control period.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a CSAPR NO_x Ozone Season Group 1 source under this subpart, in which any CSAPR NO_x Ozone Season Group 1 allowance allocations to the CSAPR NO_x Ozone Season Group 1 units at the source are recorded and in which are held any CSAPR NO_x Ozone Season Group 1 allowances available for use for a control period in a given year in complying with the source's CSAPR NO_x Ozone Season Group 1 emissions limitation in accordance with §§ 97.506 and 97.524.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_x emissions, stack gas volumetric flow rate, stack gas moisture content, and O₂ or CO₂ concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.530 through 97.535. The following systems are the principal types of continuous emission monitoring systems:

- (1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);
- (2) A NO_x concentration monitoring system, consisting of a NO_x pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_x emissions, in parts per million (ppm);
- (3) A NO_x emission rate (or NO_x-diluent) monitoring system, consisting of a NO_x pollutant concentration monitor, a diluent gas (CO₂ or O₂) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_x concentration, in parts per million (ppm), diluent gas concentration, in percent CO₂ or O₂, and NO_x emission rate, in pounds per million British thermal units (lb/mmBtu);
- (4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H₂O;
- (5) A CO₂ monitoring system, consisting of a CO₂ pollutant concentration monitor (or an O₂ monitor plus suitable mathematical equations from which the CO₂ concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO₂ emissions, in percent CO₂; and
- (6) An O₂ monitoring system, consisting of an O₂ concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O₂, in percent O₂.

Control period means the period starting May 1 of a calendar year, except as provided in § 97.506(c)(3), and ending on September 30 of the same year, inclusive.

CSAPR NO_x Annual Trading Program means a multi-state NO_x air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO_x.

CSAPR NO_x Ozone Season Expanded Group 2 allowance means a CSAPR NO_x Ozone Season Group 2 allowance allocated for a control period after 2022 under subpart EEEEE of this part or § 97.1026(e)(1)(ii) or (e)(2)(ii) to a unit in a State listed in § 52.38(b)(2)(ii)(D)(1) of this chapter (and Indian country within the borders of such a State) or allocated or auctioned for a control period after 2022 in accordance with the provisions of a SIP revision approved after November 6, 2024 for such a State by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter.

CSAPR NO_x Ozone Season Group 1 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(3), (4), or (5) of this chapter, to emit one ton of NO_x during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_x Ozone Season Group 1 Trading Program.

CSAPR NO_x Ozone Season Group 1 allowance deduction or deduct CSAPR NO_x Ozone Season Group 1 allowances

means the permanent withdrawal of CSAPR NO_x Ozone Season Group 1 allowances by the Administrator from a compliance account (e.g., in order to account for compliance with the CSAPR NO_x Ozone Season Group 1 emissions limitation) or from an assurance account (e.g., in order to account for compliance with the assurance provisions under §§ 97.506 and 97.525).

CSAPR NO_x Ozone Season Group 1 allowances held or hold CSAPR NO_x Ozone Season Group 1 allowances means the CSAPR NO_x Ozone Season Group 1 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

- (1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, CSAPR NO_x Ozone Season Group 1 allowance transfer in accordance with this subpart; and
- (2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CSAPR NO_x Ozone Season Group 1 allowance transfer in accordance with this subpart.

CSAPR NO_x Ozone Season Group 1 emissions limitation means, for a CSAPR NO_x Ozone Season Group 1 source, the tonnage of NO_x emissions authorized in a control period in a given year by the CSAPR NO_x Ozone Season Group 1 allowances available for deduction for the source under § 97.524(a) for such control period.

CSAPR NO_x Ozone Season Group 1 source means a source that includes one or more CSAPR NO_x Ozone Season Group 1 units.

CSAPR NO_x Ozone Season Group 1 Trading Program means a multi-state NO_x air pollution control and emission reduction program established in accordance with this subpart and § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_x.

CSAPR NO_x Ozone Season Group 1 unit means a unit that is subject to the CSAPR NO_x Ozone Season Group 1 Trading Program.

CSAPR NO_x Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart EEEEE of this part, § 97.526, or § 97.1026, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter, to emit one ton of NO_x during a control period of the specified calendar year for which the

authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_x Ozone Season Group 2 Trading Program, where each CSAPR NO_x Ozone Season Group 2 allowance is either a CSAPR NO_x Ozone Season Original Group 2 allowance or a CSAPR NO_x Ozone Season Expanded Group 2 allowance.

CSAPR NO_x Ozone Season Group 2 Trading Program means a multi-state NO_x air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and § 52.38(b)(1), (b)(2)(ii), and (b)(7) through (9), (13), (14), and (16) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(9) of this chapter), as a means of mitigating interstate transport of ozone and NO_x.

CSAPR NO_x Ozone Season Group 3 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart GGGGG of this part or § 97.826, or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(10), (11), or (12) of this chapter, to emit one ton or less of NO_x during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_x Ozone Season Group 3 Trading Program.

CSAPR NO_x Ozone Season Group 3 Trading Program means a multi-state NO_x air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_x.

CSAPR NO_x Ozone Season Original Group 2 allowance means a CSAPR NO_x Ozone Season Group 2 allowance other than a CSAPR NO_x Ozone Season Expanded Group 2 allowance.

CSAPR SO₂ Group 1 Trading Program means a multi-state SO₂ air pollution control and emission reduction program established in accordance with subpart CCCCC of this part and § 52.39(a), (b), (d) through (f), and (j) through (l) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(d) or (e) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO₂.

CSAPR SO₂ Group 2 Trading Program means a multi-state SO₂ air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO₂.

Designated representative means, for a CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CSAPR NO_x Ozone Season Group 1 Trading Program. If the CSAPR NO_x Ozone Season Group 1 source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR SO₂ Group 1 Trading Program, or CSAPR SO₂ Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

- (1) In accordance with this subpart; and
- (2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the CSAPR NO_x Ozone Season Group 1 units at a CSAPR NO_x Ozone Season Group 1 source during a control period in a given year that exceeds the CSAPR NO_x Ozone Season Group 1 emissions limitation for the source for such control period.

Fossil fuel means—

- (1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or
- (2) For purposes of applying the limitation on “average annual fuel consumption of fossil fuel” in § 97.504(b)(2)(i)(B) and (b)(2)(ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

- (1) For the life of the unit;
- (2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
- (3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input rate means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means “natural gas” as defined in § 72.2 of this chapter.

Newly affected CSAPR NO_x Ozone Season Group 1 unit means a unit that was not a CSAPR NO_x Ozone Season Group 1 unit when it began operating but that thereafter becomes a CSAPR NO_x Ozone Season Group 1 unit.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide (N₂O), reported on an equivalent molecular weight basis as nitrogen dioxide (NO₂).

Operate or operation means, with regard to a unit, to combust fuel.

Operator means, for a CSAPR NO_x Ozone Season Group 1 source or a CSAPR NO_x Ozone Season Group 1 unit at a source respectively, any person who operates, controls, or supervises a CSAPR NO_x Ozone Season Group 1 unit at the source or the CSAPR NO_x Ozone Season Group 1 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a CSAPR NO_x Ozone Season Group 1 source or a CSAPR NO_x Ozone Season Group 1 unit at a source respectively, any of the following persons:

- (1) Any holder of any portion of the legal or equitable title in a CSAPR NO_x Ozone Season Group 1 unit at the source or the CSAPR NO_x Ozone Season Group 1 unit;
- (2) Any holder of a leasehold interest in a CSAPR NO_x Ozone Season Group 1 unit at the source or the CSAPR NO_x Ozone Season Group 1 unit, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CSAPR NO_x Ozone Season Group 1 unit; and
- (3) Any purchaser of power from a CSAPR NO_x Ozone Season Group 1 unit at the source or the CSAPR NO_x Ozone Season Group 1 unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means “permitting authority” as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit (in MWh/yr), 33 percent of the unit's maximum design heat input rate (in Btu/hr), divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CSAPR NO_x Ozone Season Group 1 allowances, the moving of CSAPR NO_x Ozone Season Group 1 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

- (1) The use of reject heat from electricity production in a useful thermal energy application or process; or
- (2) The use of reject heat from a useful thermal energy application or process in electricity production.

Serial number means, for a CSAPR NO_x Ozone Season Group 1 allowance, the unique identification number assigned to each CSAPR NO_x Ozone Season Group 1 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the CSAPR NO_x Ozone Season Group 1 Trading Program pursuant to § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

- (1) In person;
- (2) By United States Postal Service; or
- (3) By other means of dispatch or transmission and delivery;
- (4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$\text{LHV} = \text{HHV} - 10.55 (W + 9H)$$

where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy 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).

Useful thermal energy means thermal energy that is:

- (1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
- (2) Used in a heating application (e.g., space heating or domestic hot water heating); or
- (3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74608, Oct. 26, 2016; 86 FR 23185, Apr. 30, 2021; 88 FR 36898, June 5, 2023; 88 FR 49304, July 31, 2023; 89 FR 87970, Nov. 6, 2024]

§ 97.503 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit

CO₂—carbon dioxide

CSAPR—Cross-State Air Pollution Rule

H₂O—water

hr—hour

kWh—kilowatt-hour

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt-hour

NO_x—nitrogen oxides

O₂—oxygen

ppm—parts per million

scfh—standard cubic feet per hour

SIP—State implementation plan

SO₂—sulfur dioxide

TR—Transport Rule

yr—year

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74609, Oct. 26, 2016]

§ 97.504 Applicability.

(a) Except as provided in paragraph (b) of this section:

- (1) The following units in a State (and Indian country within the borders of such State) shall be CSAPR NO_x Ozone Season Group 1 units, and any source that includes one or more such units shall be a CSAPR NO_x Ozone Season Group 1 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CSAPR NO_x Ozone Season Group 1 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CSAPR NO_x Ozone Season Group 1 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a CSAPR NO_x Ozone Season Group 1 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (b)(2)(i) of this section shall not be a CSAPR NO_x Ozone Season Group 1 unit:

(1)

(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit's potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a CSAPR NO_x Ozone Season Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a CSAPR NO_x Ozone Season Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a CSAPR NO_x Ozone Season Group 1 unit.

(2)

(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a CSAPR NO_x Ozone Season Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(2)(i) of this section, the unit shall become a CSAPR NO_x Ozone Season Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a CSAPR NO_x Ozone Season Group 1 unit.

- (c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, of the CSAPR NO_x Ozone Season Group 1 Trading Program to the unit or other equipment.
- (1) **Petition content.** The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment 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."
- (2) **Response.** The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CSAPR NO_x Ozone Season Group 1 Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74609, Oct. 26, 2016; 86 FR 23186, Apr. 30, 2021]

§ 97.505 Retired unit exemption.

- (a)
- (1) Any CSAPR NO_x Ozone Season Group 1 unit that is permanently retired shall be exempt from § 97.506(b) and (c)(1), § 97.524, and §§ 97.530 through 97.535.
- (2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CSAPR NO_x Ozone Season Group 1 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.
- (b)
- (1) A unit exempt under paragraph (a) of this section shall not emit any NO_x, starting on the date that the exemption takes effect.
- (2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

- (3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CSAPR NO_x Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
- (4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

[76 FR 48406, Aug. 8, 2011, as amended at 86 FR 23186, Apr. 30, 2021]

§ 97.506 Standard requirements.

- (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 §§ 97.513 through 97.518.
- (b) **Emissions monitoring, reporting, and recordkeeping requirements.**
 - (1) The owners and operators, and the designated representative, of each CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.530 through 97.535.
 - (2) The emissions data determined in accordance with §§ 97.530 through 97.535 shall be used to calculate allocations of CSAPR NO_x Ozone Season Group 1 allowances under §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the CSAPR NO_x Ozone Season Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, 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 §§ 97.530 through 97.535 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 —**
 - (1) **CSAPR NO_x Ozone Season Group 1 emissions limitation.**
 - (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall hold, in the source's compliance account, CSAPR NO_x Ozone Season Group 1 allowances available for deduction for such control period under § 97.524(a) in an amount not less than the tons of total NO_x emissions for such control period from all CSAPR NO_x Ozone Season Group 1 units at the source.
 - (ii) If total NO_x emissions during a control period in a given year from the CSAPR NO_x Ozone Season Group 1 units at a CSAPR NO_x Ozone Season Group 1 source are in excess of the CSAPR NO_x Ozone Season Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:
 - (A) The owners and operators of the source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall hold the CSAPR NO_x Ozone Season Group 1 allowances required for deduction under § 97.524(d); and

- (B) The owners and operators of the source and each CSAPR NO_x Ozone Season Group 1 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 this subpart and the Clean Air Act.
- (2) *CSAPR NO_x Ozone Season Group 1 assurance provisions.*
- (i) If total NO_x emissions during a control period in a given year from all CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in a State (and Indian country within the borders of such 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) CSAPR NO_x Ozone Season Group 1 allowances available for deduction for such control period under § 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.525(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 (and Indian country within the borders of such 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 CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.
 - (ii) The owners and operators shall hold the CSAPR NO_x Ozone Season Group 1 allowances required under paragraph (c)(2)(i) of this section, 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.
 - (iii) Total NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in a State (and Indian country within the borders of such 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 1 trading budget under § 97.510(a) and the State's variability limit under § 97.510(b).
 - (iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in a State (and Indian country within the borders of such 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 CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

- (v) To the extent the owners and operators fail to hold CSAPR NO_x Ozone Season Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,
 - (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 CSAPR NO_x Ozone Season Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.
- (3) **Compliance periods.**
 - (i) A CSAPR NO_x Ozone Season Group 1 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter.
 - (ii) A CSAPR NO_x Ozone Season Group 1 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter.
- (4) **Vintage of CSAPR NO_x Ozone Season Group 1 allowances held for compliance.**
 - (i) A CSAPR NO_x Ozone Season Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NO_x Ozone Season Group 1 allowance that was allocated or auctioned for such control period or a control period in a prior year.
 - (ii) A CSAPR NO_x Ozone Season Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NO_x Ozone Season Group 1 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.
- (5) **Allowance Management System requirements.** Each CSAPR NO_x Ozone Season Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.
- (6) **Limited authorization.** A CSAPR NO_x Ozone Season Group 1 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:
 - (i) Such authorization shall only be used in accordance with the CSAPR NO_x Ozone Season Group 1 Trading Program; and
 - (ii) Notwithstanding any other provision of this subpart, 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.
- (7) **Property right.** A CSAPR NO_x Ozone Season Group 1 allowance does not constitute a property right.

(d) *Title V permit requirements.*

- (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Ozone Season Group 1 allowances in accordance with this subpart.
- (2) A description of whether a unit is required to monitor and report NO_x emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.530 through 97.535 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.*

- (1) Unless otherwise provided, the owners and operators of each CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 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.
 - (i) The certificate of representation under § 97.516 for the designated representative for the source and each CSAPR NO_x Ozone Season Group 1 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 § 97.516 changing the designated representative.
 - (ii) All emissions monitoring information, in accordance with this subpart.
 - (iii) 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 CSAPR NO_x Ozone Season Group 1 Trading Program.
- (2) The designated representative of a CSAPR NO_x Ozone Season Group 1 source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall make all submissions required under the CSAPR NO_x Ozone Season Group 1 Trading Program, except as provided in § 97.518. 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 parts 70 and 71 of this chapter.

(f) *Liability.*

- (1) Any provision of the CSAPR NO_x Ozone Season Group 1 Trading Program that applies to a CSAPR NO_x Ozone Season Group 1 source or the designated representative of a CSAPR NO_x Ozone Season Group 1 source shall also apply to the owners and operators of such source and of the CSAPR NO_x Ozone Season Group 1 units at the source.

(2) Any provision of the CSAPR NO_x Ozone Season Group 1 Trading Program that applies to a CSAPR NO_x Ozone Season Group 1 unit or the designated representative of a CSAPR NO_x Ozone Season Group 1 unit shall also apply to the owners and operators of such unit.

(g) **Effect on other authorities.** No provision of the CSAPR NO_x Ozone Season Group 1 Trading Program or exemption under § 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_x Ozone Season Group 1 source or CSAPR NO_x Ozone Season Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[76 FR 48406, Aug. 8, 2011, as amended at 77 FR 10336, Feb. 21, 2012; 79 FR 71672, Dec. 3, 2014; 81 FR 74609, Oct. 26, 2016; 86 FR 23186, Apr. 30, 2021]

§ 97.507 Computation of time.

- (a) Unless otherwise stated, any time period scheduled, under the CSAPR NO_x Ozone Season Group 1 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.
- (b) Unless otherwise stated, any time period scheduled, under the CSAPR NO_x Ozone Season Group 1 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.
- (c) Unless otherwise stated, if the final day of any time period, under the CSAPR NO_x Ozone Season Group 1 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.508 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the CSAPR NO_x Ozone Season Group 1 Trading Program are set forth in part 78 of this chapter.

§ 97.509 [Reserved]

§ 97.510 State NO_x Ozone Season Group 1 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State NO_x Ozone Season Group 1 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR NO_x Ozone Season Group 1 allowances for the control periods in the years indicated are as follows:

(1) **Alabama.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 31,746 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 635 tons.
- (iii)-(vi) [Reserved]

(2) **Arkansas.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 15,110 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 756 tons.
- (iii)-(vi) [Reserved]

(3) **Florida.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 28,644 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 544 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 29 tons.
- (iv)-(vi) [Reserved]

(4) **Georgia.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 27,944 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 559 tons.
- (iii) [Reserved]
- (iv) The NO_x Ozone Season Group 1 trading budget for 2017 and thereafter is 24,041 tons.
- (v) The new unit set-aside for 2017 and thereafter is 485 tons.
- (vi) [Reserved]

(5) **Illinois.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 21,208 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,697 tons.
- (iii)-(vi) [Reserved]

(6) **Indiana.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 46,876 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,406 tons.
- (iii)-(vi) [Reserved]

(7) **Iowa.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 16,532 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 314 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 17 tons.
- (iv)-(vi) [Reserved]

(8) **Kentucky.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 36,167 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,447 tons.
- (iii)-(vi) [Reserved]

(9) **Louisiana.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 18,115 tons.

(ii) The new unit set-aside for 2015 and 2016 is 344 tons.

(iii) The Indian country new unit set-aside for 2015 and 2016 is 18 tons.

(iv)-(vi) [Reserved]

(10) **Maryland.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 7,179 tons.

(ii) The new unit set-aside for 2015 and 2016 is 144 tons.

(iii)-(vi) [Reserved]

(11) **Michigan.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 28,041 tons.

(ii) The new unit set-aside for 2015 and 2016 is 533 tons.

(iii) The Indian country new unit set-aside for 2015 and 2016 is 28 tons.

(iv)-(vi) [Reserved]

(12) **Mississippi.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 12,429 tons.

(ii) The new unit set-aside for 2015 and 2016 is 237 tons.

(iii) The Indian country new unit set-aside for 2015 and 2016 is 12 tons.

(iv)-(vi) [Reserved]

(13) **Missouri.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 22,788 tons.

(ii) The new unit set-aside for 2015 is 684 tons and for 2016 is 1,367 tons.

(iii)-(vi) [Reserved]

(14) **New Jersey.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 4,128 tons.

(ii) The new unit set-aside for 2015 and 2016 is 83 tons.

(iii)-(vi) [Reserved]

(15) **New York.**

(i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 10,369 tons.

(ii) The new unit set-aside for 2015 and 2016 is 197 tons.

(iii) The Indian country new unit set-aside for 2015 and 2016 is 10 tons.

(iv)-(vi) [Reserved]

(16) **North Carolina.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 22,168 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,308 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 22 tons.
- (iv)-(vi) [Reserved]

(17) **Ohio.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 41,284 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 826 tons.
- (iii)-(vi) [Reserved]

(18) **Oklahoma.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 is 36,567 tons and for 2016 is 22,694 tons.
- (ii) The new unit set-aside for 2015 is 731 tons and for 2016 is 454 tons.
- (iii)-(vi) [Reserved]

(19) **Pennsylvania.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 52,201 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,044 tons.
- (iii)-(vi) [Reserved]

(20) **South Carolina.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 13,909 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 264 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 14 tons.
- (iv)-(vi) [Reserved]

(21) **Tennessee.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 14,908 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 298 tons.
- (iii)-(vi) [Reserved]

(22) **Texas.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 65,560 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 2,556 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 66 tons.
- (iv)-(vi) [Reserved]

(23) **Virginia.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 14,452 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 723 tons.
- (iii)-(vi) [Reserved]

(24) **West Virginia.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 25,283 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 1,264 tons.
- (iii)-(vi) [Reserved]

(25) **Wisconsin.**

- (i) The NO_x Ozone Season Group 1 trading budget for 2015 and 2016 is 14,784 tons.
- (ii) The new unit set-aside for 2015 and 2016 is 872 tons.
- (iii) The Indian country new unit set-aside for 2015 and 2016 is 15 tons.
- (iv)-(vi) [Reserved]

- (b) The States' variability limits for the State NO_x Ozone Season Group 1 trading budgets for the control periods in 2017 and thereafter are as follows:

(1)-(3) [Reserved]

(4) The variability limit for Georgia is 5,049 tons.

(5)-(25) [Reserved]

- (c) Each State NO_x Ozone Season Group 1 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

[77 FR 10336, Feb. 21, 2012, as amended at 77 FR 10348, Feb. 21, 2012; 77 FR 34845, June 12, 2012; 79 FR 71672, Dec. 3, 2014; 81 FR 74609, Oct. 26, 2016; 86 FR 23186, Apr. 30, 2021]

§ 97.511 Timing requirements for CSAPR NO_x Ozone Season Group 1 allowance allocations.

(a) **Existing units.**

- (1) CSAPR NO_x Ozone Season Group 1 allowances are allocated, for the control periods in 2015 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a CSAPR NO_x Ozone Season Group 1 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_x Ozone Season Group 1 unit.
- (2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2014, during the control period in two consecutive years, such unit will not be allocated the CSAPR NO_x Ozone Season Group 1 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All CSAPR NO_x Ozone Season Group 1 allowances that would otherwise have been allocated to such unit will be allocated to the

new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate CSAPR NO_x Ozone Season Group 1 allowances to the unit in accordance with paragraph (b) of this section.

(b) **New units —**

(1) **New unit set-asides.**

(i)

- (A) By June 1 of each year from 2015 through 2020, the Administrator will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in a State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance with § 97.512(a)(2) through (7) and (12) and §§ 97.506(b)(2) and 97.530 through 97.535, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.
- (B) By March 1, 2022 and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in a State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance with § 97.512(a)(2) through (7), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

- (A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_x Ozone Season Group 1 units) are in accordance with the provisions referenced in paragraph (b)(1)(i)(A) or (B) of this section, as applicable.
- (B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(i)(A) or (B) of this section, as applicable. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i)(A) of this section, or by May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i)(B) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii)

- (A) If the new unit set-aside for the control period in 2015 or 2016 contains any CSAPR NO_x Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability

that identifies any CSAPR NO_x Ozone Season Group 1 units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period.

- (B) If the new unit set-aside for the control period in a year from 2017 through 2020 contains any CSAPR NO_x Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_x Ozone Season Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.
- (iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_x Ozone Season Group 1 units in such notice.
 - (A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_x Ozone Season Group 1 units in such notice is in accordance with paragraph (b)(1)(iii) of this section.
 - (B) The Administrator will adjust the identification of CSAPR NO_x Ozone Season Group 1 units in each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in accordance with § 97.512(a)(9), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii)(A) of this section, or by February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii)(B) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_x Ozone Season Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.
- (v) To the extent any CSAPR NO_x Ozone Season Group 1 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section for a control period before 2021, or in paragraph (b)(1)(ii) of this section for a control period in 2021 or thereafter, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_x Ozone Season Group 1 allowances in accordance with § 97.512(a)(10).

(2) *Indian country new unit set-asides.*

(i)

- (A) By June 1 of each year from 2015 through 2020, the Administrator will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with § 97.512(b)(2) through (7) and (12) and §§

97.506(b)(2) and 97.530 through 97.535, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

- (B) By March 1, 2022 and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with § 97.512(b)(2) through (7), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.
- (ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.
 - (A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_x Ozone Season Group 1 units) are in accordance with the provisions referenced in paragraph (b)(2)(i)(A) or (B) of this section, as applicable.
 - (B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i)(A) or (B) of this section, as applicable. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i)(A) of this section, or by May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i)(B) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.
- (iii)
 - (A) If the Indian country new unit set-aside for the control period in 2015 or 2016 contains any CSAPR NO_x Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_x Ozone Season Group 1 units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period.
 - (B) If the Indian country new unit set-aside for the control period in a year from 2017 through 2020 contains any CSAPR NO_x Ozone Season Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any CSAPR NO_x Ozone Season Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period.

- (iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of CSAPR NO_x Ozone Season Group 1 units in such notice.
 - (A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of CSAPR NO_x Ozone Season Group 1 units in such notice is in accordance with paragraph (b)(2)(iii) of this section.
 - (B) The Administrator will adjust the identification of CSAPR NO_x Ozone Season Group 1 units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the CSAPR NO_x Ozone Season Group 1 allowance allocation to each CSAPR NO_x Ozone Season Group 1 unit in accordance with § 97.512(b)(9), (10), and (12) and §§ 97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(A) of this section, or by February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of CSAPR NO_x Ozone Season Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.
- (v) To the extent any CSAPR NO_x Ozone Season Group 1 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section for a control period before 2021, or in paragraph (b)(2)(ii) of this section for a control period in 2021 or thereafter, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such CSAPR NO_x Ozone Season Group 1 allowances in accordance with § 97.512(b)(10).

(c) *Units incorrectly allocated CSAPR NO_x Ozone Season Group 1 allowances.*

- (1) For each control period in 2015 and thereafter, if the Administrator determines that CSAPR NO_x Ozone Season Group 1 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 97.512(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:
 - (i)
 - (A) The recipient is not actually a CSAPR NO_x Ozone Season Group 1 unit under § 97.504 as of May 1, 2015 and is allocated CSAPR NO_x Ozone Season Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, the recipient is not actually a CSAPR NO_x

Ozone Season Group 1 unit as of May 1, 2015 and is allocated CSAPR NO_x Ozone Season Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_x Ozone Season Group 1 units as of May 1, 2015; or

- (B) The recipient is not located as of May 1 of the control period in the State from whose NO_x Ozone Season Group 1 trading budget the CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under § 52.38(b)(3), (4), or (5) of this chapter, were allocated for such control period.
- (ii) The recipient is not actually a CSAPR NO_x Ozone Season Group 1 unit under § 97.504 as of May 1 of such control period and is allocated CSAPR NO_x Ozone Season Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, the recipient is not actually a CSAPR NO_x Ozone Season Group 1 unit as of May 1 of such control period and is allocated CSAPR NO_x Ozone Season Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are CSAPR NO_x Ozone Season Group 1 units as of May 1 of such control period.
- (2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_x Ozone Season Group 1 allowances under § 97.521.
- (3) If the Administrator already recorded such CSAPR NO_x Ozone Season Group 1 allowances under § 97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_x Ozone Season Group 1 allowances were recorded an amount of CSAPR NO_x Ozone Season Group 1 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_x Ozone Season Group 1 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_x Ozone Season Group 1 allowances in such account for completion of the deduction.
- (4) If the Administrator already recorded such CSAPR NO_x Ozone Season Group 1 allowances under § 97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_x Ozone Season Group 1 allowances.
- (5)
 - (i) With regard to the CSAPR NO_x Ozone Season Group 1 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:
 - (A) Transfer such CSAPR NO_x Ozone Season Group 1 allowances to the new unit set-aside for such control period (or a subsequent control period) for the State from whose NO_x Ozone Season Group 1 trading budget the CSAPR NO_x Ozone Season Group 1 allowances were allocated; or

- (B) If the State has a SIP revision approved under § 52.38(b)(4) or (5) of this chapter covering such control period, include such CSAPR NO_x Ozone Season Group 1 allowances in the portion of the State NO_x Ozone Season Group 1 trading budget that may be allocated for such control period (or a subsequent control period) in accordance with such SIP revision.
- (ii) With regard to the CSAPR NO_x Ozone Season Group 1 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:
 - (A) Transfer such CSAPR NO_x Ozone Season Group 1 allowances to the new unit set-aside for such control period (or a subsequent control period); or
 - (B) If the State has a SIP revision approved under § 52.38(b)(4) or (5) of this chapter covering such control period, include such CSAPR NO_x Ozone Season Group 1 allowances in the portion of the State NO_x Ozone Season Group 1 trading budget that may be allocated for such control period (or a subsequent control period) in accordance with such SIP revision.
- (iii) With regard to the CSAPR NO_x Ozone Season Group 1 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CSAPR NO_x Ozone Season Group 1 allowances to the Indian country new unit set-aside for such control period (or a subsequent control period).

[76 FR 48379, Aug. 8, 2011, as amended at 79 FR 71672, Dec. 3, 2014; 81 FR 74609, Oct. 26, 2016; 86 FR 23186, Apr. 30, 2021; 88 FR 36898, June 5, 2023]

§ 97.512 CSAPR NO_x Ozone Season Group 1 allowance allocations to new units.

- (a) *Allocations from new unit set-asides.* For each control period in 2015 and thereafter and for the CSAPR NO_x Ozone Season Group 1 units in each State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator will allocate CSAPR NO_x Ozone Season Group 1 allowances to the CSAPR NO_x Ozone Season Group 1 units as follows:
 - (1) The CSAPR NO_x Ozone Season Group 1 allowances will be allocated to the following CSAPR NO_x Ozone Season Group 1 units, except as provided in paragraph (a)(10) of this section:
 - (i) CSAPR NO_x Ozone Season Group 1 units that are not allocated an amount of CSAPR NO_x Ozone Season Group 1 allowances in the notice of data availability issued under § 97.511(a)(1) and that have deadlines for certification of monitoring systems under § 97.530(b) not later than September 30 of the year of the control period;
 - (ii) CSAPR NO_x Ozone Season Group 1 units whose allocation of an amount of CSAPR NO_x Ozone Season Group 1 allowances for such control period in the notice of data availability issued under § 97.511(a)(1) is covered by § 97.511(c)(2) or (3);
 - (iii) CSAPR NO_x Ozone Season Group 1 units that are allocated an amount of CSAPR NO_x Ozone Season Group 1 allowances for such control period in the notice of data availability issued under § 97.511(a)(1), which allocation is terminated for such control period pursuant to §

97.511(a)(2), and that operate during the control period immediately preceding such control period, for allocations for a control period before 2021, or that operate during such control period, for allocations for a control period in 2021 or thereafter; or

- (iv) For purposes of paragraph (a)(9) of this section, CSAPR NO_x Ozone Season Group 1 units under § 97.511(c)(1)(ii) whose allocation of an amount of CSAPR NO_x Ozone Season Group 1 allowances for such control period in the notice of data availability issued under § 97.511(b)(1)(ii)(B) is covered by § 97.511(c)(2) or (3).
- (2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_x Ozone Season Group 1 allowances in an amount equal to the applicable amount of tons of NO_x emissions as set forth in § 97.510(a) and will be allocated additional CSAPR NO_x Ozone Season Group 1 allowances (if any) in accordance with § 97.511(a)(2) and (c)(5) and paragraph (b)(10) of this section.
- (3) The Administrator will determine, for each CSAPR NO_x Ozone Season Group 1 unit described in paragraph (a)(1) of this section, an allocation of CSAPR NO_x Ozone Season Group 1 allowances for the latest of the following control periods and for each subsequent control period:
 - (i) The control period in 2015;
 - (ii)
 - (A) The first control period after the control period in which the CSAPR NO_x Ozone Season Group 1 unit commences commercial operation, for allocations for a control period before 2021; or
 - (B) The control period containing the deadline for certification of the CSAPR NO_x Ozone Season Group 1 unit's monitoring systems under § 97.530(b), for allocations for a control period in 2021 or thereafter;
 - (iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_x Ozone Season Group 1 unit operates in the State and areas of Indian country within the borders of the State subject to the State's SIP authority after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_x Ozone Season Group 1 allowances; and
 - (iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation, for allocations for a control period before 2021, or the control period in which the unit resumes operation, for allocations for a control period in 2021 or thereafter.
- (4)
 - (i) The allocation to each CSAPR NO_x Ozone Season Group 1 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_x emissions during the immediately preceding control period, for allocations for a control period before 2021, or the unit's total tons of NO_x emissions during the control period, for allocations for a control period in 2021 or thereafter.
 - (ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) of this section in accordance with paragraphs (a)(5) through (7) and (12) of this section.

- (5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_x Ozone Season Group 1 allowances determined for all such CSAPR NO_x Ozone Season Group 1 units under paragraph (a)(4)(i) of this section in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for such control period.
- (6) If the amount of CSAPR NO_x Ozone Season Group 1 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_x Ozone Season Group 1 allowances determined for each such CSAPR NO_x Ozone Season Group 1 unit under paragraph (a)(4)(i) of this section.
- (7) If the amount of CSAPR NO_x Ozone Season Group 1 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such CSAPR NO_x Ozone Season Group 1 unit the amount of the CSAPR NO_x Ozone Season Group 1 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_x Ozone Season Group 1 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.
- (8) For a control period before 2021, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(i) and (ii), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.
- (9) For a control period before 2021, if, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated CSAPR NO_x Ozone Season Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_x Ozone Season Group 1 allowances as follows—
 - (i)
 - (A) For the control period in 2015 or 2016, the Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_x Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(1)(ii) for the unit for such control period;
 - (B) For the control period in 2017, 2018, 2019, or 2020, the Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_x Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(1)(ii) for the unit for such control period;
 - (ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

- (iii) If the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_x Ozone Season Group 1 allowances determined for each such CSAPR NO_x Ozone Season Group 1 unit under paragraph (a)(9)(i) of this section; and
 - (iv) If the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_x Ozone Season Group 1 unit the amount of the CSAPR NO_x Ozone Season Group 1 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.
- (10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for a control period before 2021, or under paragraphs (a)(2) through (7) and (12) of this section for a control period in 2021 or thereafter, any unallocated CSAPR NO_x Ozone Season Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_x Ozone Season Group 1 unit that is in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated an amount of CSAPR NO_x Ozone Season Group 1 allowances in the notice of data availability issued under § 97.511(a)(1), and continues to be allocated CSAPR NO_x Ozone Season Group 1 allowances for such control period in accordance with § 97.511(a)(2), an amount of CSAPR NO_x Ozone Season Group 1 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_x Ozone Season Group 1 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.511(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_x Ozone Season Group 1 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.
- (11)
- (i) For a control period before 2021, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(iii), (iv), and (v), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.
 - (ii) For a control period in 2021 or thereafter, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(i), (ii), and (v), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (a)(2) through (7), (10), and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.
- (12) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations from a new unit set-aside for a control period before 2021 under paragraph (a)(7) of this section, paragraphs (a)(6) and (a)(9)(iv) of this section, or paragraphs (a)(6), (a)(9)(iii), and (a)(10) of this section, or for a control period in 2021 or thereafter under paragraph (a)(7) of this section or paragraphs (a)(6) and (10) of this section, would otherwise result in total allocations from such new unit set-aside unequal to the total amount of such new unit set-aside,

then the Administrator will adjust the results of such calculations as follows. The Administrator will list the CSAPR NO_x Ozone Season Group 1 units in descending order based on such units' allocation amounts under paragraph (a)(7), (a)(9)(iv), or (a)(10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount under such paragraph upward or downward by one CSAPR NO_x Ozone Season Group 1 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total allocations from such new unit set-aside equal the total amount of such new unit set-aside.

- (b) *Allocations from Indian country new unit set-asides.* For each control period in 2015 and thereafter and for the CSAPR NO_x Ozone Season Group 1 units in areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator will allocate CSAPR NO_x Ozone Season Group 1 allowances to the CSAPR NO_x Ozone Season Group 1 units as follows:
- (1) The CSAPR NO_x Ozone Season Group 1 allowances will be allocated to the following CSAPR NO_x Ozone Season Group 1 units, except as provided in paragraph (b)(10) of this section:
 - (i) CSAPR NO_x Ozone Season Group 1 units that are not allocated an amount of CSAPR NO_x Ozone Season Group 1 allowances in the notice of data availability issued under § 97.511(a)(1) and that have deadlines for certification of monitoring systems under § 97.530(b) not later than September 30 of the year of the control period; or
 - (ii) For purposes of paragraph (b)(9) of this section, CSAPR NO_x Ozone Season Group 1 units under § 97.511(c)(1)(ii) whose allocation of an amount of CSAPR NO_x Ozone Season Group 1 allowances for such control period in the notice of data availability issued under § 97.511(b)(2)(ii)(B) is covered by § 97.511(c)(2) or (3).
 - (2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_x Ozone Season Group 1 allowances in an amount equal to the applicable amount of tons of NO_x emissions as set forth in § 97.510(a) and will be allocated additional CSAPR NO_x Ozone Season Group 1 allowances (if any) in accordance with § 97.511(c)(5).
 - (3) The Administrator will determine, for each CSAPR NO_x Ozone Season Group 1 unit described in paragraph (b)(1) of this section, an allocation of CSAPR NO_x Ozone Season Group 1 allowances for the later of the following control periods and for each subsequent control period:
 - (i) The control period in 2015; and
 - (ii)
 - (A) The first control period after the control period in which the CSAPR NO_x Ozone Season Group 1 unit commences commercial operation, for allocations for a control period before 2021; or
 - (B) The control period containing the deadline for certification of the CSAPR NO_x Ozone Season Group 1 unit's monitoring systems under § 97.530(b), for allocations for a control period in 2021 or thereafter.

(4)

- (i) The allocation to each CSAPR NO_x Ozone Season Group 1 unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of NO_x emissions during the immediately preceding control period, for allocations for a control period before 2021, or the unit's total tons of NO_x emissions during the control period, for allocations for a control period in 2021 or thereafter.
 - (ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) of this section in accordance with paragraphs (b)(5) through (7) and (12) of this section.
- (5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_x Ozone Season Group 1 allowances determined for all such CSAPR NO_x Ozone Season Group 1 units under paragraph (b)(4)(i) of this section in areas of Indian country within the borders of the State not subject to the State's SIP authority for such control period.
 - (6) If the amount of CSAPR NO_x Ozone Season Group 1 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of CSAPR NO_x Ozone Season Group 1 allowances determined for each such CSAPR NO_x Ozone Season Group 1 unit under paragraph (b)(4)(i) of this section.
 - (7) If the amount of CSAPR NO_x Ozone Season Group 1 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such CSAPR NO_x Ozone Season Group 1 unit the amount of the CSAPR NO_x Ozone Season Group 1 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of CSAPR NO_x Ozone Season Group 1 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.
 - (8) For a control period before 2021, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(2)(i) and (ii), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.
 - (9) For a control period before 2021, if, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated CSAPR NO_x Ozone Season Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such CSAPR NO_x Ozone Season Group 1 allowances as follows—
 - (i)
 - (A) For the control period in 2015 or 2016, the Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_x Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(2)(ii) for the unit for such control period;
 - (B) For the control period in 2017, 2018, 2019, or 2020, the Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control

period and ending November 30 of the year of such control period, the positive difference (if any) between the unit's emissions during such control period and the amount of CSAPR NO_x Ozone Season Group 1 allowances referenced in the notice of data availability required under § 97.511(b)(2)(ii) for the unit for such control period;

- (ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;
 - (iii) If the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of CSAPR NO_x Ozone Season Group 1 allowances determined for each such CSAPR NO_x Ozone Season Group 1 unit under paragraph (b)(9)(i) of this section; and
 - (iv) If the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such CSAPR NO_x Ozone Season Group 1 unit the amount of the CSAPR NO_x Ozone Season Group 1 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated CSAPR NO_x Ozone Season Group 1 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.
- (10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for a control period before 2021, or under paragraphs (b)(2) through (7) and (12) of this section for a control period in 2021 or thereafter, any unallocated CSAPR NO_x Ozone Season Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:
- (i) Transfer such unallocated CSAPR NO_x Ozone Season Group 1 allowances to the new unit set-aside for the State for such control period; or
 - (ii) If the State has a SIP revision approved under § 52.38(b)(4) or (5) of this chapter covering such control period, include such unallocated CSAPR NO_x Ozone Season Group 1 allowances in the portion of the State NO_x Ozone Season Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.
- (11)
- (i) For a control period before 2021, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(2)(iii), (iv), and (v), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.
 - (ii) For a control period in 2021 or thereafter, the Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(2)(i), (ii), and (v), of the amount of CSAPR NO_x Ozone Season Group 1 allowances allocated under paragraphs (b)(2) through (7), (10), and (12) of this section for such control period to each CSAPR NO_x Ozone Season Group 1 unit eligible for such allocation.

- (12) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations from an Indian country new unit set-aside for a control period before 2021 under paragraph (b)(7) of this section or paragraphs (b)(6) and (b)(9)(iv) of this section, or for a control period in 2021 or thereafter under paragraph (b)(7) of this section, would otherwise result in total allocations from such Indian country new unit set-aside unequal to the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of such calculations as follows. The Administrator will list the CSAPR NO_x Ozone Season Group 1 units in descending order based on such units' allocation amounts under paragraph (b)(7) or (b)(9)(iv) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount under such paragraph upward or downward by one CSAPR NO_x Ozone Season Group 1 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total allocations from such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

[76 FR 48379, Aug. 8, 2011, as amended at 79 FR 71672, Dec. 3, 2014; 81 FR 74610, Oct. 26, 2016; 86 FR 23187, Apr. 30, 2021; 88 FR 36898, June 5, 2023]

§ 97.513 Authorization of designated representative and alternate designated representative.

- (a) Except as provided under § 97.515, each CSAPR NO_x Ozone Season Group 1 source, including all CSAPR NO_x Ozone Season Group 1 units at the source, shall have one and only one designated representative, with regard to all matters under the CSAPR NO_x Ozone Season Group 1 Trading Program.
- (1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_x Ozone Season Group 1 units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).
- (2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516:
- (i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each CSAPR NO_x Ozone Season Group 1 unit at the source in all matters pertaining to the CSAPR NO_x Ozone Season Group 1 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and
- (ii) The owners and operators of the source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.
- (b) Except as provided under § 97.515, each CSAPR NO_x Ozone Season Group 1 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.
- (1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all CSAPR NO_x Ozone Season Group 1 units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

- (2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516,
 - (i) The alternate designated representative shall be authorized;
 - (ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and
 - (iii) The owners and operators of the source and each CSAPR NO_x Ozone Season Group 1 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.
- (c) Except in this section, § 97.502, and §§ 97.514 through 97.518, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.514 Responsibilities of designated representative and alternate designated representative.

- (a) Except as provided under § 97.518 concerning delegation of authority to make submissions, each submission under the CSAPR NO_x Ozone Season Group 1 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each CSAPR NO_x Ozone Season Group 1 source and CSAPR NO_x Ozone Season Group 1 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: “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.”
- (b) The Administrator will accept or act on a submission made for a CSAPR NO_x Ozone Season Group 1 source or a CSAPR NO_x Ozone Season Group 1 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.518.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

- (a) **Changing designated representative.** The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the CSAPR NO_x Ozone Season Group 1 source and the CSAPR NO_x Ozone Season Group 1 units at the source.
- (b) **Changing alternate designated representative.** The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by

the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the CSAPR NO_x Ozone Season Group 1 source and the CSAPR NO_x Ozone Season Group 1 units at the source.

(c) ***Changes in owners and operators.***

- (1) In the event an owner or operator of a CSAPR NO_x Ozone Season Group 1 source or a CSAPR NO_x Ozone Season Group 1 unit at the source is not included in the list of owners and operators in the certificate of representation under § 97.516, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.
- (2) Within 30 days after any change in the owners and operators of a CSAPR NO_x Ozone Season Group 1 source or a CSAPR NO_x Ozone Season Group 1 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.516 amending the list of owners and operators to reflect the change.

(d) ***Changes in units at the source.*** Within 30 days of any change in which units are located at a CSAPR NO_x Ozone Season Group 1 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under § 97.516 amending the list of units to reflect the change.

- (1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.
- (2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.516 Certificate of representation.

- (a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:
 - (1) Identification of the CSAPR NO_x Ozone Season Group 1 source, and each CSAPR NO_x Ozone Season Group 1 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a

statement of whether such source is located in Indian country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

- (2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.
 - (3) A list of the owners and operators of the CSAPR NO_x Ozone Season Group 1 source and of each CSAPR NO_x Ozone Season Group 1 unit at the source.
 - (4) The following certification statements by the designated representative and any alternate designated representative—
 - (i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CSAPR NO_x Ozone Season Group 1 unit at the source.”
 - (ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_x Ozone Season Group 1 Trading Program on behalf of the owners and operators of the source and of each CSAPR NO_x Ozone Season Group 1 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.”
 - (iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CSAPR NO_x Ozone Season Group 1 unit, or where a utility or industrial customer purchases power from a CSAPR NO_x Ozone Season Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CSAPR NO_x Ozone Season Group 1 unit at the source; and CSAPR NO_x Ozone Season Group 1 allowances and proceeds of transactions involving CSAPR NO_x Ozone Season Group 1 allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CSAPR NO_x Ozone Season Group 1 allowances by contract, CSAPR NO_x Ozone Season Group 1 allowances and proceeds of transactions involving CSAPR NO_x Ozone Season Group 1 allowances will be deemed to be held or distributed in accordance with the contract.”
 - (5) The signature of the designated representative and any alternate designated representative and the dates signed.
- (b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.
 - (c) A certificate of representation under this section that complies with the provisions of paragraph (a) of this section except that it contains the phrase “TR NO_x Ozone Season” in place of the phrase “CSAPR NO_x Ozone Season Group 1” in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted for purposes of this subpart as if the phrase “CSAPR NO_x Ozone Season Group 1” appeared in place of the phrase “TR NO_x Ozone Season”.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74611, Oct. 26, 2016]

§ 97.517 Objections concerning designated representative and alternate designated representative.

- (a) Once a complete certificate of representation under § 97.516 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.516 is received by the Administrator.
- (b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CSAPR NO_X Ozone Season Group 1 Trading Program.
- (c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CSAPR NO_X Ozone Season Group 1 allowance transfers.

§ 97.518 Delegation by designated representative and alternate designated representative.

- (a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.
- (b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.
- (c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:
 - (1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;
 - (2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");
 - (3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and
 - (4) The following certification statements by such designated representative or alternate designated representative:
 - (i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.518 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.519 [Reserved]

§ 97.520 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) **Compliance accounts.** Upon receipt of a complete certificate of representation under § 97.516, the Administrator will establish a compliance account for the CSAPR NO_x Ozone Season Group 1 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) **Assurance accounts.** The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.525(b)(3).

(c) **General accounts —**

(1) **Application for general account.**

(i) Any person may apply to open a general account, for the purpose of holding and transferring CSAPR NO_x Ozone Season Group 1 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

- (A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;
 - (B) An identifying name for the general account;
 - (C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CSAPR NO_x Ozone Season Group 1 allowances held in the general account;
 - (D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CSAPR NO_x Ozone Season Group 1 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account."; and
 - (E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.
- (iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.
- (iv) An application for a general account under paragraph (c)(1) of this section that complies with the provisions of such paragraph except that it contains the phrase "TR NO_x Ozone Season" in place of the phrase "CSAPR NO_x Ozone Season Group 1" in the required certification statement will be considered a complete application for a general account under such paragraph, and the certification statement included in such application for a general account will be interpreted for purposes of this subpart as if the phrase "CSAPR NO_x Ozone Season Group 1" appeared in place of the phrase "TR NO_x Ozone Season".
- (2) ***Authorization of authorized account representative and alternate authorized account representative.***
- (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:
 - (A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances held in the general account in all matters pertaining to the CSAPR NO_x Ozone Season Group 1 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

- (B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.
 - (C) Each person who has an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.
- (ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CSAPR NO_x Ozone Season Group 1 allowances held in the general account. 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."
 - (iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.
 - (iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the phrase "TR NO_x Ozone Season" will be interpreted for purposes of this subpart as if the phrase "CSAPR NO_x Ozone Season Group 1" appeared in place of the phrase "TR NO_x Ozone Season".
- (3) ***Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.***
- (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CSAPR NO_x Ozone Season Group 1 allowances in the general account.
 - (ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized

account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CSAPR NO_x Ozone Season Group 1 allowances in the general account.

(iii)

- (A) In the event a person having an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.
- (B) Within 30 days after any change in the persons having an ownership interest with respect to CSAPR NO_x Ozone Season Group 1 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CSAPR NO_x Ozone Season Group 1 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.*

- (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.
- (ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CSAPR NO_x Ozone Season Group 1 Trading Program.
- (iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CSAPR NO_x Ozone Season Group 1 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.*

- (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

- (ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.
- (iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:
 - (A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;
 - (B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);
 - (C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;
 - (D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv) shall be deemed to be an electronic submission by me.”; and
 - (E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.520(c)(5) is terminated.”.
- (iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.
- (v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) *Closing a general account.*

- (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted CSAPR NO_x Ozone Season Group 1 allowance transfer under § 97.522 for any CSAPR NO_x Ozone Season Group 1 allowances in the account to one or more other Allowance Management System accounts.
- (ii) If a general account has no CSAPR NO_x Ozone Season Group 1 allowance transfers to or from the account for a 12-month period or longer and does not contain any CSAPR NO_x Ozone Season Group 1 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CSAPR NO_x Ozone Season Group 1 allowance transfer under § 97.522 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.
- (d) **Account identification.** The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.
- (e) **Responsibilities of authorized account representative and alternate authorized account representative.** After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CSAPR NO_x Ozone Season Group 1 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.514(a) and 97.518 or paragraphs (c)(2)(ii) and (c)(5) of this section.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74611, Oct. 26, 2016; 86 FR 23188, Apr. 30, 2021]

§ 97.521 Recordation of CSAPR NO_x Ozone Season Group 1 allowance allocations and auction results.

- (a) By November 7, 2011 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 26, 2015, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.511(a) for the control period in 2015.
- (b) By November 7, 2011 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 26, 2015, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.511(a) for the control period in 2016, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 or, with regard to CSAPR NO_x Ozone Season Group 1 units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 6, 2015 of the State's intent to submit to the Administrator a complete SIP revision by April 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2015 meeting the requirements of § 52.38(b)(3)(i) through (iv) of this chapter.
- (1) If, by April 1, 2015 or, with regard to CSAPR NO_x Ozone Season Group 1 units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, by October 1, 2015, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 15, 2015 in each

CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.511(a) for the control period in 2016.

(2) If the State submits to the Administrator by April 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2015, and the Administrator approves by October 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2016, such complete SIP revision, the Administrator will record by October 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2016 in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source as provided in such approved, complete SIP revision for the control period in 2016.

(3) If the State submits to the Administrator by April 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2015, and the Administrator does not approve by October 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2016, such complete SIP revision, the Administrator will record by October 1, 2015 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2016 in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.511(a) for the control period in 2016.

(c) By January 9, 2017, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control periods in 2017 and 2018.

(d) By July 1, 2017, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control periods in 2019 and 2020.

(e) By July 1, 2018, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control periods in 2021 and 2022.

(f)

(1) By July 1, 2019 and July 1, 2020, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to

CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

- (2) By July 1, 2024 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.511(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the year after the year of the applicable recordation deadline under this paragraph.

(g)

- (1) By August 1 of each year from 2015 through 2020, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.512(a)(2) through (8) and (12), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.
- (2) By May 1, 2022 and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_x Ozone Season Group 1 allowances auctioned to CSAPR NO_x Ozone Season Group 1 units, in accordance with § 97.512(a), or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(h)

- (1) By August 1 of each year from 2015 through 2020, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.
- (2) By May 1, 2022 and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(b) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(i)

- (1) By November 15, 2015 and November 15, 2016, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(a)(9) through (12) for the control period in the year of the applicable recordation deadline under this paragraph.

- (2) By February 15 of each year from 2018 through 2021, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(a)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j)

- (1) By November 15, 2015 and November 15, 2016, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(b)(9) through (12) for the control period in the year of the applicable recordation deadline under this paragraph.

- (2) By February 15 of each year from 2018 through 2021, the Administrator will record in each CSAPR NO_x Ozone Season Group 1 source's compliance account the CSAPR NO_x Ozone Season Group 1 allowances allocated to the CSAPR NO_x Ozone Season Group 1 units at the source in accordance with § 97.512(b)(9) through (12) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

- (k) By the date 15 days after the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (j) of this section, of CSAPR NO_x Ozone Season Group 1 allowances to a recipient is made by or are submitted to the Administrator in accordance with § 97.511 or § 97.512 or with a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

- (l) When recording the allocation or auction of CSAPR NO_x Ozone Season Group 1 allowances to a CSAPR NO_x Ozone Season Group 1 unit or other entity in an Allowance Management System account, the Administrator will assign each CSAPR NO_x Ozone Season Group 1 allowance a unique identification number that will include digits identifying the year of the control period for which the CSAPR NO_x Ozone Season Group 1 allowance is allocated or auctioned.

[76 FR 48406, Aug. 8, 2011, as amended at 76 FR 80777, Dec. 27, 2011; 79 FR 71672, Dec. 3, 2014; 81 FR 74611, Oct. 26, 2016; 86 FR 23188, Apr. 30, 2021; 87 FR 52481, Aug. 26, 2022]

§ 97.522 Submission of CSAPR NO_x Ozone Season Group 1 allowance transfers.

- (a) An authorized account representative seeking recordation of a CSAPR NO_x Ozone Season Group 1 allowance transfer shall submit the transfer to the Administrator.
- (b) A CSAPR NO_x Ozone Season Group 1 allowance transfer shall be correctly submitted if:
 - (1) The transfer includes the following elements, in a format prescribed by the Administrator:
 - (i) The account numbers established by the Administrator for both the transferor and transferee accounts;
 - (ii) The serial number of each CSAPR NO_x Ozone Season Group 1 allowance that is in the transferor account and is to be transferred; and
 - (iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

- (2) When the Administrator attempts to record the transfer, the transferor account includes each CSAPR NO_x Ozone Season Group 1 allowance identified by serial number in the transfer.

§ 97.523 Recordation of CSAPR NO_x Ozone Season Group 1 allowance transfers.

- (a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CSAPR NO_x Ozone Season Group 1 allowance transfer that is correctly submitted under § 97.522, the Administrator will record a CSAPR NO_x Ozone Season Group 1 allowance transfer by moving each CSAPR NO_x Ozone Season Group 1 allowance from the transferor account to the transferee account as specified in the transfer.
- (b) A CSAPR NO_x Ozone Season Group 1 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CSAPR NO_x Ozone Season Group 1 allowances allocated or auctioned for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 97.524 for the control period immediately before such allowance transfer deadline.
- (c) Where a CSAPR NO_x Ozone Season Group 1 allowance transfer is not correctly submitted under § 97.522, the Administrator will not record such transfer.
- (d) Within 5 business days of recordation of a CSAPR NO_x Ozone Season Group 1 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.
- (e) Within 10 business days of receipt of a CSAPR NO_x Ozone Season Group 1 allowance transfer that is not correctly submitted under § 97.522, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:
- (1) A decision not to record the transfer, and
- (2) The reasons for such non-recordation.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74612, Oct. 26, 2016]

§ 97.524 Compliance with CSAPR NO_x Ozone Season Group 1 emissions limitation.

- (a) **Availability for deduction for compliance.** CSAPR NO_x Ozone Season Group 1 allowances are available to be deducted for compliance with a source's CSAPR NO_x Ozone Season Group 1 emissions limitation for a control period in a given year only if the CSAPR NO_x Ozone Season Group 1 allowances:
- (1) Were allocated or auctioned for such control period or a control period in a prior year; and
- (2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.
- (b) **Deductions for compliance.** After the recordation, in accordance with § 97.523, of CSAPR NO_x Ozone Season Group 1 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account CSAPR NO_x Ozone Season Group 1 allowances available under paragraph (a) of this section in order to determine whether the source meets the CSAPR NO_x Ozone Season Group 1 emissions limitation for such control period, as follows:

- (1) Until the amount of CSAPR NO_x Ozone Season Group 1 allowances deducted equals the number of tons of total NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units at the source for such control period; or
 - (2) If there are insufficient CSAPR NO_x Ozone Season Group 1 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CSAPR NO_x Ozone Season Group 1 allowances available under paragraph (a) of this section remain in the compliance account.
- (c) **Selection of CSAPR NO_x Ozone Season Group 1 allowances for deduction –**
- (1) **Identification by serial number.** The designated representative for a source may request that specific CSAPR NO_x Ozone Season Group 1 allowances, identified by serial number, in the source's compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the CSAPR NO_x Ozone Season Group 1 source and the appropriate serial numbers.
 - (2) **First-in, first-out.** The Administrator will deduct CSAPR NO_x Ozone Season Group 1 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of CSAPR NO_x Ozone Season Group 1 allowances in such request, on a first-in, first-out accounting basis in the following order:
 - (i) Any CSAPR NO_x Ozone Season Group 1 allowances that were recorded in the compliance account pursuant to § 97.521 and not transferred out of the compliance account, in the order of recordation; and then
 - (ii) Any other CSAPR NO_x Ozone Season Group 1 allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.
- (d) **Deductions for excess emissions.** After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the CSAPR NO_x Ozone Season Group 1 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CSAPR NO_x Ozone Season Group 1 allowances, allocated or auctioned for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions.
- (e) **Recordation of deductions.** The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74612, Oct. 26, 2016; 86 FR 23189, Apr. 30, 2021]

§ 97.525 Compliance with CSAPR NO_x Ozone Season Group 1 assurance provisions.

- (a) **Availability for deduction.** CSAPR NO_x Ozone Season Group 1 allowances are available to be deducted for compliance with the CSAPR NO_x Ozone Season Group 1 assurance provisions for a control period in a given year by the owners and operators of a group of one or more CSAPR NO_x Ozone Season Group 1 sources and units in a State (and Indian country within the borders of such State) only if the CSAPR NO_x Ozone Season Group 1 allowances:

- (1) Were 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; and
- (2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of CSAPR NO_x Ozone Season Group 1 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) **Deductions for compliance.** The Administrator will deduct CSAPR NO_x Ozone Season Group 1 allowances available under paragraph (a) of this section for compliance with the CSAPR NO_x Ozone Season Group 1 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

- (1) By June 1 of each year from 2018 through 2021 and August 1 of each year thereafter, the Administrator will:
 - (i) Calculate, for each State (and Indian country within the borders of such State), the total NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO_x emissions exceed the State assurance level as described in § 97.506(c)(2)(iii); and
 - (ii) For the set of any States (and Indian country within the borders of such States) for which the results of the calculations required in paragraph (b)(1)(i) of this section indicate that total NO_x emissions exceed the respective State assurance levels for such control period—
 - (A) Calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more CSAPR NO_x Ozone Season Group 1 sources and units in such State (and such Indian country), the common designated representative's share of the total NO_x emissions from all CSAPR NO_x Ozone Season Group 1 units at CSAPR NO_x Ozone Season Group 1 sources in such State (and such Indian country), the common designated representative's assurance level, and the amount (if any) of CSAPR NO_x Ozone Season Group 1 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in § 97.506(c)(2)(i); and
 - (B) Promulgate a notice of data availability of the results of the calculations required in paragraphs (b)(1)(i) and (b)(1)(ii)(A) of this section, including separate calculations of the NO_x emissions from each CSAPR NO_x Ozone Season Group 1 source in each such State (and Indian country within the borders of such State).
- (2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice of data availability required in paragraph (b)(1)(ii) of this section.
 - (i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in such notice are in accordance with § 97.506(c)(2)(iii), §§ 97.506(b) and 97.530 through 97.535, the definitions of "common designated representative", "common designated representative's assurance level", and "common designated representative's share" in § 97.502, and the calculation formula in § 97.506(c)(2)(i).

- (ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.
- (3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(ii) of this section as having CSAPR NO_x Ozone Season Group 1 units with total NO_x emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(ii) of this section, as all of the owners and operators of a group of CSAPR NO_x Ozone Season Group 1 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold CSAPR NO_x Ozone Season Group 1 allowances.
- (4)
 - (i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(ii) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of CSAPR NO_x Ozone Season Group 1 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.
 - (ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.
- (5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(ii) of this section and after the recordation, in accordance with § 97.523, of CSAPR NO_x Ozone Season Group 1 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of CSAPR NO_x Ozone Season Group 1 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(ii) of this section.
- (6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(ii) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of CSAPR NO_x Ozone Season Group 1 allowances that the

owners and operators are required to hold in accordance with § 97.506(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(ii) of this section, except as follows:

- (i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of CSAPR NO_x Ozone Season Group 1 allowances that owners and operators are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for such control period with regard to the CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section.
- (ii) [Reserved]
- (iii) If the revised data are used to recalculate, in accordance with paragraph (b)(6)(i) of this section, the amount of CSAPR NO_x Ozone Season Group 1 allowances that the owners and operators are required to hold for such control period with regard to the CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) involved—
 - (A) Where the amount of CSAPR NO_x Ozone Season Group 1 allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of CSAPR NO_x Ozone Season Group 1 allowances in the assurance account established by the Administrator for the appropriate CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners' and operators' failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners' and operators' failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each CSAPR NO_x Ozone Season Group 1 allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.
 - (B) For the owners and operators for which the amount of CSAPR NO_x Ozone Season Group 1 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which CSAPR NO_x Ozone Season Group 1 allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate CSAPR NO_x Ozone Season Group 1 sources, CSAPR NO_x Ozone Season Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the CSAPR NO_x Ozone Season Group 1 allowances held in such assurance account equal to the amount of the decrease. If CSAPR NO_x Ozone Season Group 1 allowances were transferred to such assurance account from more than one account, the amount of CSAPR NO_x Ozone Season Group 1 allowances recorded in each

such transferor account will be in proportion to the percentage of the total amount of CSAPR NO_x Ozone Season Group 1 allowances transferred to such assurance account for such control period from such transferor account.

- (C) Each CSAPR NO_x Ozone Season Group 1 allowance held under paragraph (b)(6)(iii)(A) of this section as a result of recalculation of requirements under the CSAPR NO_x Ozone Season Group 1 assurance provisions for such control period must be a CSAPR NO_x Ozone Season Group 1 allowance allocated for a control period in a year before or the year immediately following, or in the same year as, the year of such control period.

[76 FR 48406, Aug. 8, 2011, as amended at 77 FR 10338, Feb. 21, 2012; 79 FR 71672, Dec. 3, 2014; 81 FR 74612, Oct. 26, 2016; 86 FR 23189, Apr. 30, 2021]

§ 97.526 Banking and conversion.

- (a) A CSAPR NO_x Ozone Season Group 1 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.
- (b) Any CSAPR NO_x Ozone Season Group 1 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_x Ozone Season Group 1 allowance is deducted or transferred under § 97.511(c), § 97.523, § 97.524, § 97.525, § 97.527, or § 97.528 or paragraph (c) or (d) of this section.
- (c) At any time after the allowance transfer deadline for the last control period for which a State NO_x Ozone Season Group 1 trading budget is established under § 97.510(a) for a given State and after completion of the procedures under paragraph (d)(1) of this section, the Administrator may record a transfer of any CSAPR NO_x Ozone Season Group 1 allowances held in the compliance account for a source in such State (and Indian country within the borders of such State) to a general account identified or established by the Administrator with the source's designated representative as the authorized account representative and with the owners and operators of the source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative. The Administrator will notify the designated representative not less than 15 days before making such a transfer.
- (d) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b)(4) or (5) of this chapter:
 - (1) As soon as practicable after the completion of deductions under § 97.524 for the control period in 2016, but not later than March 1, 2018, the Administrator will temporarily suspend acceptance of CSAPR NO_x Ozone Season Group 1 allowance transfers submitted under § 97.522 and, before resuming acceptance of such transfers, will take the actions in paragraphs (d)(1)(i) through (iii) of this section with regard to every general account and every compliance account except a compliance account for a CSAPR NO_x Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(i)(A) of this chapter (and Indian country within the borders of such a State):
 - (i) The Administrator will deduct all CSAPR NO_x Ozone Season Group 1 allowances allocated for the control periods in 2015 and 2016 from each such account.

- (ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the sum of all CSAPR NO_x Ozone Season Group 1 allowances deducted from all such accounts under paragraph (d)(1)(i) of this section divided by the product of 1.5 multiplied by the sum of the variability limits for the control period in 2017 set forth in § 97.810(b) for all States listed in § 52.38(b)(2)(ii) of this chapter.
- (iii) The Administrator will allocate and record in each such account an amount of CSAPR NO_x Ozone Season Original Group 2 allowances for the control period in 2017 computed as the quotient, rounded up to the nearest allowance, of the number of CSAPR NO_x Ozone Season Group 1 allowances deducted from such account under paragraph (d)(1)(i) of this section divided by the conversion factor determined under paragraph (d)(1)(ii) of this section, except as provided in paragraph (d)(1)(iv) of this section.
- (iv) Where, pursuant to paragraph (d)(1)(i) of this section, the Administrator deducts CSAPR NO_x Ozone Season Group 1 allowances from the compliance account for a source in a State not listed in § 52.38(b)(2)(ii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record CSAPR NO_x Ozone Season Original Group 2 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO_x Ozone Season Original Group 2 allowances for the control period in 2017 computed for such source in accordance with paragraph (d)(1)(iii) of this section in a general account identified by the designated representative for such source, provided that if the designated representative fails to identify such a general account in a submission to the Administrator by July 14, 2021, the Administrator may record such CSAPR NO_x Ozone Season Original Group 2 allowances in a general account identified or established by the Administrator with the designated representative as the authorized account representative and with the owners and operators of such source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative.

(2) {Reserved}

- (e) Notwithstanding any other provision of this subpart or any SIP revision approved under § 52.38(b)(4) or (5) of this chapter, CSAPR NO_x Ozone Season Original Group 2 allowances, CSAPR NO_x Ozone Season Expanded Group 2 allowances, or CSAPR NO_x Ozone Season Group 3 allowances may be used to satisfy requirements to hold CSAPR NO_x Ozone Season Group 1 allowances under this subpart as follows, provided that nothing in this paragraph (e) alters the time as of which any such allowance holding requirement must be met or limits any consequence of a failure to timely meet any such allowance holding requirement:
 - (1) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and before November 6, 2024, the owner or operator of a CSAPR NO_x Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(i)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_x Ozone Season Original Group 2 allowances for the control period in 2017 (or any later control period for which the allowance transfer deadline defined in § 97.802 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_x Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section.

(2)

- (i) Except as provided in paragraph (e)(2)(ii) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(d)(1) and before November 6, 2024, the owner or operator of a CSAPR NO_x Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(ii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_x Ozone Season Group 3 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_x Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(d)(1)(i)(D).
 - (ii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and §§ 97.826(d)(1) and 97.1026(e)(1) and before November 6, 2024, the owner or operator of a CSAPR NO_x Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(iii)(D)(1) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_x Ozone Season Expanded Group 2 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.802 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_x Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(d)(1)(i)(D).
- (3) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1) and before November 6, 2024, the owner or operator of a CSAPR NO_x Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(ii)(C) of this chapter and not listed in § 52.38(b)(2)(iii)(D)(2) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_x Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_x Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).
- (4) On or after November 6, 2024, the owner or operator of a source subject to the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program for the control period in the current year and required to demonstrate compliance under such program for such control period by holding CSAPR NO_x Ozone Season Original Group 2 allowances may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in a previous year for which the allowance transfer deadline defined in § 97.502 has passed by holding instead in the source's compliance account an equal number of CSAPR NO_x Ozone Season Original Group 2 allowances for the control period in the current year.

- (5) On or after November 6, 2024, the owner or operator of a source subject to the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program for the control period in the current year and required to demonstrate compliance under such program for such control period by holding CSAPR NO_x Ozone Season Expanded Group 2 allowances may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in a previous year for which the allowance transfer deadline defined in § 97.502 has passed by holding instead in the source's compliance account an equal number of CSAPR NO_x Ozone Season Expanded Group 2 allowances for the control period in the current year.
- (6) On or after November 6, 2024, the owner or operator of a source subject to the requirements of the CSAPR NO_x Ozone Season Group 3 Trading Program for the control period in the current year may satisfy a requirement to hold a given number of CSAPR NO_x Ozone Season Group 1 allowances for the control period in a previous year for which the allowance transfer deadline defined in § 97.502 has passed by holding instead in the source's compliance account an equal number of CSAPR NO_x Ozone Season Group 3 allowances for the control period in the current year.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74612, Oct. 26, 2016; 86 FR 23189, Apr. 30, 2021; 88 FR 36899, June 5, 2023; 88 FR 49304, July 31, 2023; 89 FR 87970, Nov. 6, 2024]

§ 97.527 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.528 Administrator's action on submissions.

- (a) The Administrator may review and conduct independent audits concerning any submission under the CSAPR NO_x Ozone Season Group 1 Trading Program and make appropriate adjustments of the information in the submission.
- (b) The Administrator may deduct CSAPR NO_x Ozone Season Group 1 allowances from or transfer CSAPR NO_x Ozone Season Group 1 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

[76 FR 48406, Aug. 11, 2011, as amended at 81 FR 74614, Oct. 26, 2016]

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a CSAPR NO_x Ozone Season Group 1 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.502 and in § 72.2 of this chapter shall apply, the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CSAPR NO_x Ozone Season Group 1 unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively as defined in § 97.502, and the term “newly affected unit” shall be deemed to

mean “newly affected CSAPR NO_x Ozone Season Group 1 unit”. The owner or operator of a unit that is not a CSAPR NO_x Ozone Season Group 1 unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CSAPR NO_x Ozone Season Group 1 unit.

- (a) **Requirements for installation, certification, and data accounting.** The owner or operator of each CSAPR NO_x Ozone Season Group 1 unit shall:
- (1) Install all monitoring systems required under this subpart for monitoring NO_x mass emissions and individual unit heat input (including all systems required to monitor NO_x emission rate, NO_x concentration, stack gas moisture content, stack gas flow rate, CO₂ or O₂ concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);
 - (2) Successfully complete all certification tests required under § 97.531 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and
 - (3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.
- (b) **Compliance deadlines.** Except as provided in paragraph (e) of this section, the owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the latest of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the latest of the following dates:
- (1) May 1, 2015;
 - (2) 180 calendar days after the date on which the unit commences commercial operation; or
 - (3) Where data for the unit are reported on a control period basis under § 97.534(d)(1)(ii)(B), and where the compliance date under paragraph (b)(2) of this section is not in a month from May through September, May 1 immediately after the compliance date under paragraph (b)(2) of this section.
 - (4) The owner or operator of a CSAPR NO_x Ozone Season Group 1 unit for which construction of a new stack or flue or installation of add-on NO_x emission controls is completed after the applicable deadline under paragraph (b)(1), (2), or (3) of this section shall meet the requirements of § 75.4(e)(1) through (4) of this chapter, except that:
 - (i) Such requirements shall apply to the monitoring systems required under § 97.530 through § 97.535, rather than the monitoring systems required under part 75 of this chapter;
 - (ii) NO_x emission rate, NO_x concentration, stack gas moisture content, stack gas volumetric flow rate, and O₂ or CO₂ concentration data shall be determined and reported, rather than the data listed in § 75.4(e)(2) of this chapter; and
 - (iii) Any petition for another procedure under § 75.4(e)(2) of this chapter shall be submitted under § 97.535, rather than § 75.66 of this chapter.
- (c) **Reporting data.** The owner or operator of a CSAPR NO_x Ozone Season Group 1 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_x concentration, NO_x emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to

determine NO_x mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) **Prohibitions.**

- (1) No owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.535.
 - (2) No owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall operate the unit so as to discharge, or allow to be discharged, NO_x to the atmosphere without accounting for all such NO_x in accordance with the applicable provisions of this subpart and part 75 of this chapter.
 - (3) No owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.
 - (4) No owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:
 - (i) During the period that the unit is covered by an exemption under § 97.505 that is in effect;
 - (ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or
 - (iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.531(d)(3)(i).
- (e) **Long-term cold storage.** The owner or operator of a CSAPR NO_x Ozone Season Group 1 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

[76 FR 48379, Aug. 8, 2011, as amended at 79 FR 71672, Dec. 3, 2014; 81 FR 74614, Oct. 26, 2016]

§ 97.531 Initial monitoring system certification and recertification procedures.

- (a) The owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.530(a)(1) if the following conditions are met:
- (1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and
 - (2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

- (b) The recertification provisions of this section shall apply to a monitoring system under § 97.530(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.
- (c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_x emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.535 to determine whether the approval applies under the CSAPR NO_x Ozone Season Group 1 Trading Program.
- (d) Except as provided in paragraph (a) of this section, the owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.530(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.
 - (1) **Requirements for initial certification.** The owner or operator shall ensure that each continuous monitoring system under § 97.530(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.530(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.
 - (2) **Requirements for recertification.** Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.530(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_x mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_x monitoring system under appendix E to part 75 of this chapter, under § 97.530(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.
 - (3) **Approval process for initial certification and recertification.** For initial certification of a continuous monitoring system under § 97.530(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in § 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by the word "recertified".

- (i) **Notification of certification.** The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.533.
- (ii) **Certification application.** The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.
- (iii) **Provisional certification date.** The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CSAPR NO_x Ozone Season Group 1 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.
- (iv) **Certification application approval process.** The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CSAPR NO_x Ozone Season Group 1 Trading Program.
 - (A) **Approval notice.** If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.
 - (B) **Incomplete application notice.** If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.
 - (C) **Disapproval notice.** If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).
 - (D) **Audit decertification.** The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.532(b).

- (v) **Procedures for loss of certification.** If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:
- (A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:
 - (1) For a disapproved NO_x emission rate (i.e., NO_x-diluent) system, the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter.
 - (2) For a disapproved NO_x pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_x and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.
 - (3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO₂ concentration or the minimum potential O₂ concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.
 - (4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.
 - (5) For a disapproved excepted NO_x monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_x emission rate, as defined in § 72.2 of this chapter.
 - (B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.
 - (C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.
- (e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.
- (f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

[76 FR 48406, Aug. 11, 2011, as amended at 81 FR 74614, Oct. 26, 2016; 86 FR 23190, Apr. 30, 2021]

§ 97.532 Monitoring system out-of-control periods.

- (a) **General provisions.** Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.
- (b) **Audit decertification.** Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.531 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.531 for each disapproved monitoring system.

§ 97.533 Notifications concerning monitoring.

The designated representative of a CSAPR NO_x Ozone Season Group 1 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.534 Recordkeeping and reporting.

- (a) **General provisions.** The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.514(a).
- (b) **Monitoring plans.** The owner or operator of a CSAPR NO_x Ozone Season Group 1 unit shall comply with the requirements of § 75.73(c) and (e) of this chapter.
- (c) **Certification applications.** The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.531, including the information required under § 75.63 of this chapter.
- (d) **Quarterly reports.** The designated representative shall submit quarterly reports, as follows:
 - (1)
 - (i) If a CSAPR NO_x Ozone Season Group 1 unit is subject to the Acid Rain Program or the CSAPR NO_x Annual Trading Program or if the owner or operator of such unit chooses to report on an annual basis under this subpart, then the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_x mass emissions) for such unit for the entire year and report the NO_x mass emissions data and heat input data for such unit for the entire year.

- (ii) If a CSAPR NO_x Ozone Season Group 1 unit is not subject to the Acid Rain Program or the CSAPR NO_x Annual Trading Program, then the designated representative shall either:
 - (A) Meet the requirements of subpart H of part 75 of this chapter for such unit for the entire year and report the NO_x mass emissions data and heat input data for such unit for the entire year in accordance with paragraph (d)(1)(i) of this section; or
 - (B) Meet the requirements of subpart H of part 75 of this chapter (including the requirements in § 75.74(c) of this chapter) for such unit for the control period and report the NO_x mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year.
- (2) The designated representative shall report the NO_x mass emissions data and heat input data for a CSAPR NO_x Ozone Season Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter indicated under paragraph (d)(1) of this section beginning by the latest of:
 - (i) The calendar quarter covering May 1, 2015 through June 30, 2015;
 - (ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b); or
 - (iii) For a unit that reports on a control period basis under paragraph (d)(1)(ii)(B) of this section, if the calendar quarter under paragraph (d)(2)(ii) of this section does not include a month from May through September, the calendar quarter covering May 1 through June 30 immediately after the calendar quarter under paragraph (d)(2)(ii) of this section.
- (3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.
- (4) For CSAPR NO_x Ozone Season Group 1 units that are also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR SO₂ Group 1 Trading Program, or CSAPR SO₂ Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_x mass emission data, heat input data, and other information required by this subpart.
- (5) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.
 - (i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

- (ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(3) of this section.
- (e) **Compliance certification.** The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:
 - (1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;
 - (2) For a unit with add-on NO_x emission controls and for all hours where NO_x data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_x emissions; and
 - (3) For a unit that is reporting on a control period basis under paragraph (d)(1)(ii)(B) of this section, the NO_x emission rate and NO_x concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_x emissions.

[76 FR 48379, Aug. 8, 2011, as amended at 79 FR 71672, Dec. 3, 2014; 81 FR 74614, Oct. 26, 2016]

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

- (a) The designated representative of a CSAPR NO_x Ozone Season Group 1 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.530 through 97.534.
- (b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:
 - (1) Identification of each unit and source covered by the petition;
 - (2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;
 - (3) A description and diagram of any equipment and procedures used in the proposed alternative;
 - (4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis*; and
 - (5) Any other relevant information that the Administrator may require.
- (c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

[76 FR 48406, Aug. 8, 2011, as amended at 81 FR 74614, Oct. 26, 2016]