

Statement of Basis

Tier I Operating Permit No. T1-2014.0042

Project ID 61447

**Idaho Forest Group LLC –
Riley Creek-Moyie Springs
Moyie Springs, Idaho**

Facility ID 021-00001

Final

July 27, 2018

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LB

Permit Writer

The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

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1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BF/yr	Board feet per year
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
ESP	Electrostatic Precipitator
EPA	U.S. Environmental Protection Agency
gr/dscf	grain per dry standard cubic feet (1 lb = 7,000 grains)
HAP	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
IEU	Insignificant Emissions Units
IFG	Idaho Forest Group LLC – Riley Creek-Moyie Springs
lb/hr	pounds per hour
MACT	Maximum Achievable Control Technology
$\mu\text{g}/\text{m}^3$	micrograms per cubic meter
MMBtu	million British thermal units
MRRR	Monitoring, Recordkeeping and Reporting Requirements
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
PC	permit condition
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
TAP	toxic air pollutant
Tier I	Tier I operating permit
T/yr	tons per year
VOC	volatile organic compound

2. INTRODUCTION AND APPLICABILITY

Idaho Forest Group LLC – Riley Creek-Moyie Springs (IFG) is a manufacturer of stud lumber, located one mile off Old Highway 2. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit carbon monoxide above the major source threshold of 100 tons-per-year. The facility is also classified as a major facility, as defined by Subsection 008.10.a, because it emits or has the potential to emit above the major source thresholds of 25 tons-per-year for any combination of hazardous air pollutants (HAPs). As a major facility, IFG is required to apply for a Tier I operating permit pursuant to IDAPA 58.01.01.301. The application for a Tier I operating permit must contain a certification from IFG as to its compliance status with all applicable requirements (IDAPA 58.01.01.314.09).

IDAPA 58.01.01.362 requires that as part of its review of the Tier I application, DEQ shall prepare a technical memorandum (i.e. statement of basis) that sets forth the legal and factual basis for the draft Tier I operating permit terms and conditions including reference to the applicable statutory provisions or the draft denial. This document provides the basis for the draft Tier I operating permit for Idaho Forest Group LLC – Riley Creek-Moyie Springs.

The format of this Statement of Basis follows that of the permit. Idaho Forest Group LLC – Riley Creek-Moyie Springs Tier I operating permit is organized into sections. They are as follows:

Section 1 – Acronyms, Units, and Chemical Nomenclature

The acronyms, units, and chemical nomenclature used in the permit are defined in this section.

Section 2 - Tier I Operating Permit Scope

The scope describes this permitting action.

Section 3 - Facility-wide Conditions

The Facility-wide Conditions section contains the applicable requirements (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements (MRRR) sufficient to assure compliance with a permit condition follows the permit condition.

Sections 4 through 5 – Kipper and Sons Hog Fuel Boiler, Lumber Drying Kilns, and Planer Mills

The emissions unit-specific sections of the permit contain the applicable requirements that specifically apply to each regulated emissions unit. Some requirements that apply to an emissions unit (e.g. opacity limits) may be contained in the Facility-wide Conditions Section. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements (MRRR) sufficient to assure compliance with an applicable requirement follows the applicable requirement.

Section 7 - Non-applicable Requirements and Insignificant Activities

This section lists those requirements that the applicant has requested as non-applicable, and DEQ proposes to grant a permit shield in accordance with IDAPA 58.01.01.325.

This section contains a list of units or activities that are insignificant on the basis of size or production rate. Units and activities listed in this section must be listed in the permit application. The regulatory citation for units and activities that are insignificant on the basis of size or production rate is IDAPA 58.01.01.317.01.b.

Section 8 - General Provisions

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I facilities. The General Provisions have been reviewed by EPA and contain all terms and conditions required by IDAPA 58.01.01 et al as well as requirements from other air quality laws, rules and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and a rule or permit, the rule or permit shall govern.

3. FACILITY INFORMATION

3.1 Facility Description

IFG operates a lumber mill at Moyie Springs, Idaho. At this facility logs are delivered by truck, unloaded, and stored in the log yard. The logs are then transported from the log yard by truck and loaded onto the log deck by a dedicated crane. At the log deck, an infeeder sends the logs to one of two debarkers, which are the first step in the manufacturing process. Debarked logs are then trimmed to a desired length and transferred to the studmill. Sawing operations within the studmill reduce logs to the desired dimensions, and the lumber is then transferred to one of four kilns to be dried. After drying, the lumber is transferred to one of the planers where the lumber is milled to final dimensions and trimmed to length. The lumber is then graded, waxed or inked, stacked, and banded. Finished lumber is shipped off-site by rail or truck.

Emissions sources at the facility include a wood-fired boiler with a rated capacity of 80,000 pounds of steam per hour, four drying kilns, two planer mills, and miscellaneous sources (i.e., target boxes, railcar loading, log sawing, fuel mixing bin, screens, chippers, bark hog, debarking, and cyclones). Emissions can also be generated from traffic on unpaved surfaces.

3.2 Facility Permitting History

Tier I Operating Permit History - Previous 5-year permit term May 24, 2010 to May 24, 2015

The following information is the permitting history of this Tier I facility during the previous five-year permit term which was from May 24, 2010 to May 24, 2015. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

May 24, 2010 T1-2007.0072 Tier I operating permit renewal. (A, will be S as a result of this project)

Underlying Permit History - Includes every underlying permit issued to this facility

The following information is the comprehensive permitting history of all underlying applicable permits issued to this Tier I facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

June 4, 2018 PTC No. P-2012.0034, DEQ initiated PTC revision to correct a throughput limit (A)

May 1, 2018 PTC No. P-2012.0034, this permit was issued to increase the allowable boiler steam production rate, increase allowable kiln throughput, replace the EFB with an ESP, remove the HAPs emissions limits, and process in accordance with 209.05.c. (S)

July 8, 2014 PTC No. P-2012.0034, this permit was issued to convert the Tier II Operating Permit and Permit to Construct (T2 OP/PTC) No. P-2012.0034 Proj No. 61070 to a stand-alone PTC. This Permit to Construct (PTC) replaces T2 OP/PTC No. P-2012.0034 Project No. 61070, issued December 5, 2012. (S)

December 5, 2012 PTC/T2 P-2012.0034, this permit is a revision to limit hazardous air pollutants below major source thresholds, increase the VOC emission rate limit for the lumber drying kilns solely due to emission factor changes, and add specific VOC monitoring requirements for the kilns. This PTC/T2 revises PTC/T2 No. T2-050113, issued August 31, 2009. (S)

August 31, 2009 PTC/T2 No. T2-050113, this permit was issued to the facility to fulfill the requirements of the compliance schedule contained in the facility's Tier I operating permit, issued October 29, 2002, and modified on March 7, 2005. (S)

- August 18, 2003 PTC No. P-030119, sawmill equipment modification (re-issuance). This PTC was issued to Louisiana-Pacific Corporation. The company requested that PTC No. 021-00001, issued on July 23, 2001, be reissued because modification of the facility had not yet commenced and the July 23, 2001 PTC was due to expire. (S)
- July 23, 2001 PTC No. 021-00001, sawmill equipment modification. This PTC was issued to Louisiana-Pacific Corporation. (S)

4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

4.1 Application Scope

- This permit is for the renewal of the facility's existing Tier I operating permit No. T1-2014.0042, issued on May 24, 2010 and expired on May 24, 2015. The renewed permit will include the applicable requirements found in PTC P-2012.0034, issued to the facility on May 1, 2018.
- This permit also has Boiler MACT requirements replacing the CAM requirements of the previous permit.

4.2 Application Chronology

- November 24, 2014 DEQ received an application.
- January 23, 2015 DEQ determined that the application was complete.
- May 15, 2018 DEQ made available the draft permit and statement of basis for peer and regional office review.
- May 25, 2018 DEQ made available the draft permit and statement of basis for applicant review.
- June 14 – July 16, 2018 DEQ provided a public comment period on the proposed action.
- July 24, 2018 DEQ provided the proposed permit and statement of basis for EPA review.
- July 27, 2018 DEQ issued the final permit and statement of basis.

5. EMISSIONS UNITS, PROCESS DESCRIPTION(S), AND EMISSIONS INVENTORY

This section lists the emissions units, describes the production or manufacturing processes, and provides the emissions inventory for this facility. The information presented was provided by the applicant in its permit application. Also listed in this section are the insignificant activities based on size or production rate.

5.1 Process No. 1 – Kipper and Sons Hog Fuel Boiler

Table 5.1 lists the emissions units and control devices associated with steam production.

Table 5.1 EMISSIONS UNITS, CONTROL DEVICES, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Devices (if applicable)	Emission Point ID No.
EU #1	<u>Hog Fuel Boiler</u> Manufacturer: Kipper and Sons Burner Type: Stoker-fired unit Maximum Capacity: 80,000 pounds of steam per hour or 128 MMBtu/hr	<u>Multiclone:</u> Manufacturer: Clarage Manufacturing <u>Electrostatic Precipitator (ESP):</u> Manufacturer: Wellons Model No.: Size 8	<u>ESP Stack:</u> Height above ground: 72 ft. Exit velocity: 31.2 ft/sec Exit temperature: 309 °F Stack diameter: 5.5 ft

The facility operates a hog fuel-fired boiler. The boiler is manufactured by Kipper and Sons and is a spreader-stoker fired unit with a maximum rated design capacity of 80,000 pounds of steam per hour or 128 MMBtu/hr. The boiler was installed in 1972. The boiler is not subject to New Source Performance Standards (NSPS) because the construction date of the boiler predates all applicable NSPS regulations.

5.2 Process No. 2 – Lumber Drying Kilns – Four Total

Table 5.2 lists the emissions units and control devices associated with lumber drying.

Table 5.2 EMISSIONS UNITS, CONTROL DEVICES, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
EU #7	<u>Drying Kilns (Four Total):</u> Kilns 1-3 were manufactured by Moore. Kiln No. 4 was manufactured by Coe.	None	32 vents from four kilns. Height Above Ground: 26 ft Exit Velocity: 4.92 ft/sec Exit Temperature: 229.7 °F Stack Diameter: 1.13 ft

The facility operates four drying kilns that are used to dry green lumber. The kilns #1, #2, and #3 were manufactured by Moore. Kiln #4 was manufactured by Coe. The drying kilns are heated using steam supplied by the facility's hog fuel-fired boiler.

5.3 Process No. 3 – Planner Mills

Table 5.3 lists the emissions units and control devices associated with lumber planing and trimming.

Table 5.3 EMISSIONS UNITS, CONTROL DEVICES, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
EU #5	<p><u>Stetson Planer Mill:</u> Manufacturer: Stetson; installed in 1989 Rate: 1,600 ft/min. Shavings generated from the process are pneumatically transferred to a cyclone. A baghouse was added to the cyclone in 1994.</p>	<p><u>Cyclone:</u> Manufacturer: not available</p> <p><u>Baghouse:</u> Manufacturer: Donaldson-Day (Torit) Model: 276-RFW-10 Flow Rate: 35,200 acfm</p>	<p><u>Stetson Cyclone</u> The cyclone exhausts to the baghouse.</p> <p><u>Stetson Baghouse</u> Height Above Ground: 80.0 ft Exit Velocity: 26.9 ft/sec Exit Temperature: 68° F Stack Diameter: 1.95 ft</p>
EU #6	<p><u>Newman Planer Mill:</u> Manufacturer: Newman; installed in 1972 Rate: 1,300 ft/min. Shavings generated from the process are pneumatically transferred to a cyclone system. A baghouse was added to the cyclone in 1998.</p>	<p><u>Cyclone:</u> Manufacturer: Not available</p> <p><u>Baghouse:</u> Manufacturer: Donaldson and Company Model: 376RF8 Flow Rate: 26,500 acfm</p>	<p><u>Newman Cyclone</u> The cyclone exhausts to the baghouse.</p> <p><u>Newman Baghouse</u> Height Above Ground: 8 ft Exit Velocity: horizontal vent Exit Temperature: 68° F Stack Diameter: 2 ft</p>

After drying in the kilns, lumber is planed to final dimensions in the planer mill in one of two high speed planers (Stetson or Newman). Shavings from each of the planers are pneumatically transferred to overhead truck bins through separate cyclonic collectors, followed by rotary air locks and baghouses.

The planed lumber is then trimmed to length. Trim ends are reduced in a hog and are pneumatically transferred to the overhead truck shavings bins along with the planer shavings. The lumber is then graded, inked, stacked, banded, and stored until it is shipped off-site by rail or truck.

5.4 Insignificant Emissions Units Based on Size or Production Rate

This section contains a list of units or activities that are insignificant on the basis of size or production rate. Units and activities listed in this section must be listed in the permit application. Table 5.4 lists the units and activities which have been determined to be insignificant on the basis of size or production rate. The regulatory authority for emissions units and activities that are insignificant on the basis of size or production rate is IDAPA 58.01.01.317.01.b.

Table 5.4 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION

Emissions Unit / Activity	Regulatory Authority / Justification
Storage tanks with lids or closure < 260 gallons	IDAPA 58.01.01.317.01(b)(i)(1)
Storage tanks < 1,100 gallons, no HAPs, maximum vapor pressure 550 mm Hg.	IDAPA 58.01.01.317.01(b)(i)(2)
VOC storage tank < 10,000 gallons, with lid or closure, vapor pressure < 80 mm Hg at 21 degrees Celsius; and gasoline storage tanks with lid or closure < 10,000 gallons.	IDAPA 58.01.01.317.01(b)(i)(3)
Butane, propane and LPG storage tank < 40,000 gallons	IDAPA 58.01.01.317.01(b)(i)(4)
Combustion source < 0.50 MMBtu/hr.	IDAPA 58.01.01.317.01(b)(i)(7)
Waste paper incinerator < 0.50 MMBtu/hr.	IDAPA 58.01.01.317.01(b)(i)(8)
Welding < 1 T/day of welding rod.	IDAPA 58.01.01.317.01(b)(i)(9)
Printing using less than 2 gallons of ink.	IDAPA 58.01.01.317.01(b)(i)(12)
Surface coating, containing less than 1% by weight VOC's.	IDAPA 58.01.01.317.01(b)(i)(25)

5.5 Non-applicable Requirements for Which a Permit Shield is Requested

This section of the permit lists the regulations for which the facility has requested, and DEQ proposes to grant, a permit shield pursuant to IDAPA 58.01.01.325. The findings on which this shield is based are presented below:

- Requirements for Which a Permit Shield Will Be Granted
 - New Source Performance Standards, 40 CFR 60 Subpart Db - IFG requested a determination of non-applicability of Subpart Db- Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units (NSPS) for their Kipper and Sons hog fuel-fired boiler that was constructed in 1972. Refer to Section 6.4 of this statement of basis for more information.
- Requirements for Which a Permit Shield Will Not Be Granted
 - None identified.

5.6 Emissions Inventory

Table 5.5 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour 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 emission is state or federally enforceable.

The documentation provided with the recent application for PTC modification for P-2012.0034, issued May 1, 2018, representing the most recent emissions estimates provided by the applicant for the emissions inventory and emission factors is provided as Appendix A of this statement of basis.

Table 5.5 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr)

Source Description	PM ₁₀ T/yr	NO _x T/yr	SO ₂ T/yr	CO T/yr	VOC T/yr	Lead T/yr	HAP T/yr	Methanol (Single HAP) T/yr
Kipper and Sons Hog Fuel Fired Boiler	23.32	84.32	10.80	354	16.85	2.26E-03	7.88	--
Lumber Drying Kilns	4.07	--	--	--	74.35	--	21.13	12.79
Planer Mills	0.55	--	--	--	--	--	--	--
Total Emissions	27.94	84.32	10.8	354	91.2	0.00226	29.01	12.79

6. EMISSIONS LIMITS AND MRRR

This section contains the applicable requirements for this T1 facility.

This section is divided into the following subsections.

- Facility-Wide Conditions;
- Kipper and Sons Hog Fuel Fired Boiler (EU #1) Emissions Limits;
- Lumber Drying Kilns (EU #7) Emissions Limits;
- Planer Mills (EU #5 and EU #6) Emissions Limits;
- Tier I Operating Permit General Provisions.

MRRR

Monitoring, recordkeeping and reporting requirements (MRRR) are the means with which compliance with an applicable requirement is demonstrated. In this section, the applicable requirement (permit condition) is provided first followed by the MRRR. Should an applicable requirement not include sufficient MRRR to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit (i.e. gap filling). In addition to the specific MRRR provided for each applicable requirement, generally applicable facility-wide conditions and general provisions may also be provided, such as performance testing, reporting, and certification requirements.

The legal and factual basis for each permit condition is provided for in this document. If a permit condition was changed due to facility draft comments or public comments, an explanation of the changes is provided.

State Enforceability

An applicable requirement that is not required by the federal CAA and has not been approved by EPA as a SIP-approved requirement is identified as a "State-only" requirement and is enforceable only under state law. State-only requirements are not enforceable by the EPA or citizens under the CAA. State-only requirements are identified in the permit within the citation of the legal authority for the permit condition.

Federal Enforceability

Unless identified as "State-only," all applicable requirements, including MRRR, are state and federally enforceable. It should be noted that while a violation of a MRRR is a violation of the permit, it is not necessarily a violation of the underlying applicable requirement (e.g. emissions limit).

To minimize the length of this document, the following permit conditions and MRRR have been paraphrased. Refer to the permit for the complete requirements.

6.1 Facility-Wide Conditions

Permit Condition 3.1 - Fugitive Dust

All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651, 3/30/07]

MRRR (Permit Conditions 3.2 through 3.4)

- Monitor and maintain records of the frequency and the methods used to control fugitive dust emissions;
- Maintain records of all fugitive dust complaints received and the corrective action taken in response to the complaint;
- Conduct facility-wide inspections of all sources of fugitive emissions. If any of the sources of fugitive dust are not being reasonably controlled, corrective action is required.

[IDAPA 58.01.01.322.06, 07, 08, 4/5/2000]

Permit Condition 3.5 - Odors

The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.

[IDAPA 58.01.01.775-776 (State-only), 5/1/94]

MRRR (Permit Condition 3.6)

- Maintain records of all odor complaints received and the corrective action taken in response to the complaint;

- Take appropriate corrective action if the complaint has merit, and log the date and corrective action taken.

[IDAPA 58.01.01.322.06, 07 (State only), 5/1/94]

Permit Condition 3.7 - Visible Emissions

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.

[IDAPA 58.01.01.625, 4/5/00]

MRRR (Permit Condition 3.8 through 3.9)

- Conduct facility-wide inspections of all emissions units subject to the visible emissions standards (or rely on continuous opacity monitoring);
- If visible emissions are observed, take appropriate corrective action and/or perform a Method 9 opacity test;
- Maintain records of the results of each visible emissions inspection.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

Permit Conditions 3.10 through 3.14 - Excess Emissions

The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between the excess emissions facility wide conditions and the regulations of IDAPA 58.01.01.130-136.

MRRR (Permit Conditions 3.11 through 3.14)

Monitoring, recordkeeping and reporting requirements for excess emissions are provided in Sections 131 through 136.

- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events;
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory;
- Notify DEQ of each excess emissions events as soon as possible, including information regarding upset, breakdown, or safety events.
- Submit a report for each excess emissions event to DEQ;
- Maintain records of each excess emissions event.

Permit Condition 3.15 - Open Burning

The permittee shall comply with the *Rules for Control of Open Burning*, IDAPA 58.01.01.600-623.

[IDAPA 58.01.01.600-623, 5/08/09]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.16 - Asbestos

The permittee shall comply with all applicable requirements of 40 CFR 61, Subpart M—“National Emission Standard for Asbestos.”

[40 CFR 61, Subpart M]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.17 - Accidental Release Prevention

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process. [40 CFR 68.10 (a)]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.18- Recycling and Emissions Reductions

The permittee shall comply with applicable standards for recycling and emissions reduction of refrigerants and their substitutes pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction. [40 CFR 82, Subpart F]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.19 NESHAP General Provisions

This facility is subject to NESHAP Subpart DDDDD, and is therefore required to comply with applicable General Provisions.

[40 CFR 60/63, Subpart A]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.20 - Monitoring and Recordkeeping

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating permit. Records of monitoring information shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed 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. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Conditions 3.21 through 3.24 - Performance Testing

If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

- The type of method to be used
- Any extenuating or unusual circumstances regarding the proposed test
- The proposed schedule for conducting and reporting the test
[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

MRRR (Permit Conditions 3.22 and 3.24)

The permittee shall submit compliance test report(s) to DEQ following testing.
[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

Permit Condition 3.25 - Reports and Certifications

This permit condition establishes generally applicable MRRR for submittal of reports, certifications, and notifications to DEQ and/or EPA as specified.
[IDAPA 58.01.01.322.08, 11, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 3.26 - Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein.
[IDAPA 58.01.01.107, 4/7/11]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.
[IDAPA 58.01.01.107, 4/7/11]

Permit Condition 3.27 – Facility –Wide VOC Limit

The Idaho Forest Group facility shall emit no more than 91.2 tons per year (tpy) of VOC. VOC emissions from the dry kilns and the hog fuel boiler will be tracked as per condition 3.28 to demonstrate compliance with this requirement. For purposes of complying with this requirement, a year is defined as any consecutive 12-month period.
[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Condition 3.28)

In order to demonstrate compliance with VOC limits each month the permittee shall calculate and record the amount of VOC emissions from the drying kilns and the boiler using the emission factors listed in Table 2.1 or DEQ approved alternative. The permittee shall calculate and record the total VOC emissions during the previous consecutive 12 month period. Emission rates shall be recorded in tons per year.

Table 2.1 EMISSIONS FACTORS

Lumber Type Dried in Kilns	VOC (lb/mbf) ¹
Ponderosa Pine	2.46
Douglas Fir	1.03
Larch	0.25
Hemlock	0.24
Grand (White) Fir	0.7
Hem Fir	0.7
Lodgepole	1.32
Spruce	0.11
Engleman Spruce/Lodge Pole (ESLP)	1.32
Alpine Fir	0.7
Cedar	0.15
Any other type	2.46
Hog Fuel Boiler Emission Factor	VOC (lb/klb steam) ²
Boiler steam production (klb steam)	0.062

¹ Pounds per thousand board feet.

² Pounds per thousand pound steam.

[PTC No. P-2012.0034, 6/4/2018]

6.2 Emissions Unit No. 1 – Kipper and Sons Hogfuel Boiler

Permit Condition 4.1 – PM₁₀ / PM_{2.5} and CO Emissions Limits

The PM₁₀ and CO emissions from the boiler ESP stack shall not exceed any corresponding emissions rate limits listed in Table 4.3 of the permit.

Table 4.3 of the permit - Kipper and Sons Hog Fuel Boiler Emissions Limits^(a)

Source Description	PM ₁₀ ^(b) / PM _{2.5} ^(c)		CO
	lb/hr ^(d)	T/yr ^(e)	T/yr ^(e)
Boiler - ESP stack	6.86	23.3	353.6

- a. In absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and recordkeeping requirements.
- b. Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.84.
- c. Particulate matter with and aerodynamic diameter less than or equal to a nominal two point five (2.5) micrometers as defined in IDAPA 58.01.01.006.86.
- d. Pounds per hour. As determined by source test methods prescribed by IDAPA 58.01.01.157.
- e. Tons per consecutive 12-calendar month period.

[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Condition 4.10)

Compliance with the PM₁₀ / PM_{2.5} hourly emissions rate from the ESP stack can be determined by Permit Condition 4.10 through the performance testing at least once every five years. During the time period when performance testing is not conducted, the permittee can determine compliance with the PM₁₀ / PM_{2.5} emissions limits from the ESP stack by operating the ESP in accordance with the O&M manual. At a minimum the O&M manual must establish the following: secondary current and secondary amperage for the ESP, including the averaging periods. The O&M manual must also address voltage and amperage monitoring procedures to determine whether the ESP is operating as designed. The manual must be updated after each performance test conducted in accordance with Permit Condition 4.6. Each updated

manual shall establish ranges with averaging periods for operating parameters consistent with those achieved during the performance test, which demonstrated compliance.

Permit Condition 4.5 requires the permittee to operate the ESP within manufacturer specifications for secondary voltage and amperage applied to each transformer-rectifier set to control PM₁₀/ PM_{2.5} from the ESP stack.

In accordance with PTC No. P-2012.0034, issued on May 1, 2018, compliance with CO annual emissions limits (353.6 T/yr) can be determined by monitoring the boilers' steam production on a monthly basis and by using the CO EF (1.3 lb/10³ pounds steam) that is used in the PTC application. Steam production from the boiler is limited in Permit Condition 4.3 and monitored continuously in accordance with Permit Condition 4.7.

VOC limits that were included under this emissions unit in T1-2007.0072, issued May 24, 2010 have been moved to the Facility-Wide section of the permit as requested by the applicant in the application for modifying P-2012.0034, issued May 1, 2018.

Permit Condition 4.2 – PM Emissions Limits, IDAPA 58.01.01.677

In accordance with IDAPA 58.01.01.677, the permittee shall not discharge PM to the atmosphere from any fuel-burning equipment in excess of 0.2 gr/dscf of effluent gas corrected to 8% oxygen by volume when burning wood product.

[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Condition 4.10)

Compliance with the PM grain loading requirements is determined by a PM performance test in accordance with Permit Condition 4.10. During the time period when performance testing is not conducted, the permittee can determine compliance with the PM grain loading emissions limits from the ESP stack by operating the ESP in accordance with the O&M manual (see Permit Condition 4.6).

Permit Condition 4.3 – Steam Production Limits

The boiler shall not produce more than 544 million pounds of steam per any consecutive 12-month period.

[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Conditions 4.4 and 4.7)

Compliance with the annual steam production from the hog fuel boiler is determined by monitoring steam production in accordance with Permit Condition 4.4. The permittee will monitor and record the boiler's steam production monthly and annually to demonstrate compliance with this permit condition and in accordance with Permit Condition 4.7. Steam production will be determined by summing the monthly steam production rates over the previous consecutive 12-calendar months period.

Permit Condition 4.5 – ESP’s Operating Parameters

The secondary voltage and amperage applied to each transformer-rectifier set shall be maintained within manufacturer specifications.

[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Conditions 4.6, 4.8 and 4.9)

Permit Condition 4.6 requires the permittee to develop an O&M manual that establishes the operating ranges for the ESP operating parameters for the control of PM and PM₁₀ / PM_{2.5} emissions from the ESP stack.

Permit Condition 4.8 requires the permittee to install, calibrate, operate and maintain any equipment necessary to monitor secondary current and secondary amperage. The monitoring equipment shall be operated in accordance with manufacturer specifications and the monitoring equipment shall record on date stamped strip charts, circular charts, or electronic data logs in units of measure consistent with the specified operating parameters and averaging times.

Permit Condition 4.9 requires the permittee to develop a site specific monitoring plan in accordance with 40 CFR 63.7505. This plan shall include a semiannual inspection of the ESP for physical degradation that could affect the performance of the ESP. At a minimum, the permittee shall check the following components of the ESP for damage or other condition that would reduce the efficiency:

- Discharge electrodes
- Collection electrodes
- Electrode alignment
- Rapper mechanisms for the electrodes
- Transformer-rectifier sets

[PTC No. P-2012.0034, 6/4/2018]

Permit Condition 4.10 – Performance Tests for PM and PM₁₀ / PM_{2.5}

The permittee shall conduct a performance test to measure PM and PM₁₀/PM_{2.5} emissions from the boiler ESP primary stack to demonstrate compliance with the PM gr/dscf and PM₁₀/PM_{2.5} lb/hr limits. The performance test shall be conducted within 6 months of the ESP installation. The performance test shall be conducted under worst case normal conditions as required by IDAPA 58.01.01.157 and the General Provisions of this permit.

[PTC No. P-2012.0034, 6/4/2018]

MRRR

The performance test report shall contain documentation that the test was conducted under these conditions. The permittee is encouraged to submit a source testing protocol for approval 30 days prior to conducting the performance test. The permittee shall monitor and record the following information during the performance testing:

- Visible emissions, using methods and procedures contained in IDAPA 58.01.01.625.
- Steam produced by the boiler in pounds steam per hour, at least once every 15 minutes.
- ESP secondary voltage and secondary current, at least once every 15 minutes.

Permit Condition 4.11

The permittee is subject to emission limitations, work practice standards, and operating limits in 40 CFR 63 Subpart DDDDD. They are applicable requirements according to the Rules.

MRRR (Permit Conditions 4.12-4.26)

All MRRR are specified in the subpart and no additional MRRR is needed. Refer to the federal regulation analysis in Appendix C for details.

6.3 Emissions Unit No. 7 – Lumber Dry Kilns

The facility has four dry kilns used to dry green lumber. The kilns were manufactured either by Moore or Coe. The dry kilns are heated using steam supplied by the facility's hog fuel-fired boiler.

Permit Condition 5.1 – PM₁₀/PM_{2.5} Emissions Limits

The PM₁₀/PM_{2.5} emissions from the four lumber dry kilns vents shall not exceed any corresponding emissions rate limits listed in Table 5.3.

Table 6.1 of the permit Lumber Dry Kilns Emission Limits ^(a)

Source Description	PM _{2.5} ^(b)		PM ₁₀ ^(c)	
	lb/hr ^(d)	T/yr ^(e)	lb/hr ^(d)	T/yr ^(e)
Lumber Dry kilns – four total	30.0	3.54	38.7	4.07

- In absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and recordkeeping requirements.
- Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.84.
- Particulate matter with and aerodynamic diameter less than or equal to a nominal two point five (2.5) micrometers as defined in IDAPA 58.01.01.006.86.
- Pounds per hour. As determined by source test methods prescribed by IDAPA 58.01.01.157.
- Tons per consecutive 12-calendar month period.

[PTC No. P-2012.0034, 6/4/2018]

MRRR (Permit Condition 5.2 and 5.3, General Provision)

Compliance with Permit Condition 5.1 can be determined by Permit Condition 5.2 (throughput monitoring) and Permit Condition 5.3 (species restriction). The PM₁₀/PM_{2.5} emissions estimates are based on the amount of green lumber that is dried in the kilns. The estimated green lumber that is allowed in PTC No. P-2012.0034 is 214.3 million BF/yr - see emissions estimates in Appendix A. The PM₁₀/PM_{2.5} emissions limits are included in this permit because it is an applicable requirement and it is rolled over into this permit from PTC P-2012.0034.

The Facility-wide Permit Conditions of this permit requires consistent MRRR throughout the State. Specifically, Permit Conditions 3.10 and 3.11 apply to excess emissions reporting.

VOC limits that were included under this emissions unit in T1-2007.0072, issued May 24, 2010 have been moved to the Facility-Wide section of the permit as requested by the applicant in the application for modifying P-2012.0034, issued May 1, 2018.

6.4 Emissions Units No. 5 and 6 - Two Planer Mills

There are two planer mills (Stetson and Newman) operating at IFG.

Permit Condition 6.1 and MRRR – O&M Manual for the Baghouse

This permit condition requires the permittee to develop a baghouse procedure documents for the inspection and operation of the baghouse which control the PM and PM₁₀/PM_{2.5} emissions from the Stetson and the Newman planer mill stacks – see Permit Condition 6.1 for detail information regarding the MRRR.

6.5 General Provisions

Unless expressly stated, there are no MRRR for the general provisions.

General Compliance, Duty to Comply

The permittee must comply with the terms and conditions of the permit.

[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

General Compliance, Need to Halt or Reduce Activity Not a Defense

The permittee cannot use the fact that it would have been necessary to halt or reduce an activity as a defense in an enforcement action.

[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

General Compliance, Duty to Supplement or Correct Application

The permittee must promptly submit such supplementary facts or corrected information upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application. The permittee must also provide information as necessary to address any new requirements that become applicable after the date a complete application has been filed but prior to the release of a draft permit.

[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

Reopening, Additional Requirements, Material Mistakes, Etc.

This term lists the instances when the permit must be reopened and revised, including times when additional requirements become applicable, when the permit contains mistakes, or when revision or revocation is necessary to assure compliance with applicable requirements.

[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

Reopening, Permitting Actions

This term discusses modification, revocation, reopening, and/or reissuance of the permit for cause. If the permittee files a request to modify, revoke, reissue, or terminate the permit, the request does not stay any permit condition, nor does notification of planned changes or anticipated noncompliance.

[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

Information Requests

The permittee must furnish, within a reasonable time to DEQ, any information, including records required by the permit, that is requested in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.

[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Information Requests, Confidential Business Information

Upon request, the permittee must furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Severability

If any provision of the permit is held to be invalid, all unaffected provisions of the permit will remain in effect and enforceable.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213, or complying with IDAPA 58.01.01.220 through 223. The permittee must comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223, 4/2/08; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01.383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/11/06; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

All permit conditions are federally enforceable unless specified in the permit as a state or local only requirement. State and local only requirements are not required under the CAA and are not enforceable by EPA or by citizens.

[IDAPA 58.01.01.322.15.j, 5/1/94; IDAPA 58.01.01.322.15.k, 3/23/98; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

Inspection and Entry

Upon presentation of credentials, the facility shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

New Applicable Requirements

The permittee must continue to comply with all applicable requirements and must comply with new requirements on a timely basis.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

Certification

All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

Renewal

The permittee shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

Permit Shield

Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
 - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
 - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
 - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
 - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and
 - The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00;
IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99;
IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]

Compliance Schedule and Progress Reports

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.
- For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.
- For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.

- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.
[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00; 40 CFR 70.6(c)(3) and (4)]

Periodic Compliance Certification

The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA as specified.

- Compliance certifications for all emissions units shall be submitted annually unless otherwise specified;
- All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.
[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

False Statements

The permittee may not make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.
[IDAPA 58.01.01.125, 3/23/98]

No Tampering

The permittee may not render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.
[IDAPA 58.01.01.126, 3/23/98]

Semiannual Monitoring Reports.

In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months as specified.
[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

Each and every applicable requirement, including MRRR, is subject to prompt deviation reporting. Deviations due to excess emissions must be reported in accordance Sections 130-136. All instances of deviation from Tier I operating permit requirements must be included in the deviation reports. The reports must describe the probable cause of the deviation and any corrective action or preventative measures taken. Deviation reports must be submitted at least every six months unless the permit specifies a different time period as required by IDAPA 58.01.01.322.08.c. Examples of deviations include, but are not limited to, the following:

- Any situation in which an emissions unit fails to meet a permit term or condition
- Emission control device does not meet a required operating condition
- Observations or collected data that demonstrate noncompliance with an emissions standard
- Failure to comply with a permit term that requires a report
[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/11/06; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required, Emissions Trading

No permit revision will be required, under any approved, economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in the permit.
[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

Emergency

In accordance with IDAPA 58.01.01.332, an “emergency” as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

7. REGULATORY REVIEW

7.1 Attainment Designation (40 CFR 81.313)

The facility is located in Boundary which is designated as attainment or unclassifiable for PM₁₀, PM_{2.5}, CO, NO₂, SO_x, and Ozone. Reference 40 CFR 81.313.

7.2 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

This facility is a major facility as defined by IDAPA 58.01.01.008.10 because it emits or has the potential to emit CO and HAPS in amounts greater than or equal to major facility threshold(s) listed in Subsection 008.10. The AIRS facility classification is A.

7.3 PSD Classification (40 CFR 52.21)

From the emission inventory that was provided by the applicant (see Appendix B), the potential to emit (PTE) for the CO emission rates from the boiler is greater than 250 T/yr. Therefore, the IFG is considered a major stationary source (greater than 250 tons/year), as defined in IDAPA 58.01.01.205.01 and in 40 CFR 52.21(b). Because the facility is a PSD major, any construction or modification of a new source at the facility is subject to PSD review.

For more information about the PSD classification for this facility, please refer to the statement of basis of the PTC No. P-2012.0034, issued May 1, 2018.

7.4 NSPS Applicability (40 CFR 60)

40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The Kipper and Sons hog fuel fired boiler at the facility has a capacity of 128 MMBtu/hr and was installed in 1972, before the promulgated construction date (June 19, 1984) of the NSPS, subpart Db. Therefore, in accordance with 40 CFR 60.40b, the NSPS does not apply to the boiler

7.5 NESHAP Applicability (40 CFR 61)

No NESHAP applies to this facility.

7.6 MACT Applicability (40 CFR 63)

40 CFR 63 Subpart DDDD, National Emission Standards for Hazardous Air Pollutant: Plywood and Composite Wood Products (PCWP)

The “Plywood” MACT, 40 CFR 63.2230 *et seq.*, applies to lumber kilns located at any facility that is a major source of HAP emissions. The facility is major for HAP; therefore, this subpart applies to the facility. In accordance with 40 CFR 63.2280 (What notifications must I submit and when?), the only applicable requirement that applies to IFG is the initial notifications, as specified in 40 CFR 63.9(b)(2). On January 28, 2005, Idaho DEQ received the initial notifications for this subpart from the IFG, and it was in accordance with 40 CFR 63.2280(b); therefore, the requirement for this subpart is fulfilled. Thus, no requirements regarding this subpart is included in the Tier I operating permit renewal.

40 CFR 63 Subpart DDDDD, NESHAPS for Industrial, Commercial, and Institutional Boilers and Process Heaters

The “Boiler” MACT, 40 CFR 63.7485 specifies that the facility is subject to this subpart if the facility owns an industrial, commercial, or institutional boiler or process heater that is located at, or is part of, a

major source of HAP. IFG , Moyie Springs facility is a major source of HAP upon issuance of PTC; therefore, this subpart applies to the facility. Permit Conditions 4.11 through 4.26 incorporate the subpart into the permit.

Detailed regulatory analyses can be found in Appendix C of the SOB.

Idaho Department of Environmental Quality is delegated for both of these subparts.

7.7 CAM Applicability (40 CFR 64)

Based upon criteria pollutant emission estimates provided (refer to Appendix A for additional information), the Kipper and Sons Hogfuel Boiler has been determined to be subject to the requirements of 40 CFR 64 - Compliance Assurance Monitoring. An approved CAM plan and a complete CAM applicability analysis can be seen in the Statement of Basis for T1-2007. issued on May 24, 2010. Those CAM requirements were established before 40 CFR 63 Subpart DDDDD had been promulgated.

In accordance with 40 CFR 64.2(b)(1)(i), standards that are exempt from CAM requirements include those proposed by EPA after November 15, 1990 pursuant to section 112 of the Clean Air Act (i.e. NESHAP requirements). 40 CFR 63 Subpart DDDDD NESHAP requirements were proposed on January 13, 2003, after the November 15, 1990 exemption deadline. Therefore, the NESHAP standards of 40 CFR 63 Subpart DDDDD, including particulate matter standards, are exempt from CAM requirements. This is because the NESHAP standard has monitoring requirements that are sufficient to assure compliance with NESHAP standards. For these reasons the existing CAM requirements for particulate matter emissions from the Kipper and Sons Hogfuel Boiler will be removed from the existing Tier I operating permit.

7.8 Acid Rain Permit (40 CFR 72-75)

This facility is not an affected facility as defined in 40 CFR 72 through 75; therefore, acid rain permit requirements do not apply.

8. PUBLIC COMMENT

As required by IDAPA 58.01.01.364, a public comment period was made available to the public from June 14 to July 16, 2018. During this time, comments were not submitted in response to DEQ's proposed action.

9. EPA REVIEW OF PROPOSED PERMIT

As required by IDAPA 58.01.01.366, DEQ provided the proposed permit to EPA Region 10 for its review and comment on July 24, 2018 via e-mail. On July 24, 2018, EPA Region 10 responded to DEQ via e-mail indicating the permit is eligible for issuance.

APPENDIX A - EMISSIONS INVENTORY

APPENDIX B - FACILITY COMMENTS FOR DRAFT PERMIT

Facility Comment: Table 5.2 on Page 43 says the lumber throughput limit is 199 MMBF/yr. It is 214.3 MMBF/yr as per condition 5.2 on page 44.

DEQ Response: Table 5.2 has been corrected.

Facility Comment: Table 5.2 and condition 5.3 say that the hemlock limit is 107,150 MMBF/yr. That was in the PTC as well. The value should be 107.15 MMBF/yr.

DEQ Response: Both Table 5.2 and Permit Condition 5.3 have been corrected. Also, a DEQ initiated reissuance of the PTC is in progress to correct P-2012.0034 and will be complete before the public comment period begins.

Facility Comment: Table 2.1, page 5, says that the ESP manufacturer is Kipper and Sons. It should say Wellons. The PTC had it right.

DEQ Response: Table 2.1 has been corrected.

Facility Comment: Condition 4.18, bottom paragraph on page 30, regarding the steam flow monitor. We believe this requirement does not apply to a steam flow monitor - it is intended for a stack gas flow monitor.

DEQ Response: After consulting with the IFG Environmental Compliance Officer, it was determined that the steam flow measurement is a differential pressure transmitter connected upstream and downstream of an orifice plate in the main steam line. Therefore 40 CFR 63 7525 (f) for pressure monitoring systems applies and has replaced 40 CFR 63 7525 (e) in Permit Condition 4.18.

APPENDIX C – 40 CFR 63 SUBPART DDDDD ANALYSIS

APPENDIX A – EMISSIONS INVENTORIES

IDAHO FOREST GROUP – MOYIE SPRINGS, IDAHO
August 2017 PTC Application – Emission Inventory/Calculations

	Proposed PTE with Baseline Emission Factors						Baseline based on 2014-2016						Emissions Change					
	PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)
Point Sources																		
KIPPER & SONS HOG FUEL BOILER, EU#1	23.32	23.32	10.80	84.32	16.85	354	17.01	17.01	7.41	57.88	11.56	373.42	6.315	5.315	3.39	26.44	5.29	-19.82
EFB MEDIA BAGHOUSE EU#2	0.000	0.000	---	---	---	---	0.54	0.36	---	---	---	---	-0.542	-0.364	---	---	---	---
LUMBER DRY KILNS, EU#7	4.072	3.536	---	---	74.35	---	2.56	2.22	---	46.7	---	---	1.516	1.317	---	---	27.63	---
Fuel Bin #1 and #2 Target Boxes, EU#8 and EU#9	0.868	0.434	---	---	---	---	0.545	0.272	---	---	---	---	0.323	0.162	---	---	---	---
Hog Fuel Truck Bin TB, EY#10, 10% of hog fuel	0.096	0.048	---	---	---	---	0.061	0.030	---	---	---	---	0.036	0.018	---	---	---	---
Sawdust Truck Bin Target Box, EU#11	0.670	0.335	---	---	---	---	0.420	0.210	---	---	---	---	0.249	0.125	---	---	---	---
Chip Cyclone #2, EU#4	0.268	0.134	---	---	---	---	0.168	0.084	---	---	---	---	0.100	0.050	---	---	---	---
Green Chip Bin Target Box, EU#12	1.339	0.670	---	---	---	---	0.841	0.420	---	---	---	---	0.499	0.249	---	---	---	---
Planer Shavings Cyclone #3 BH, EU#5	0.273	0.183	---	---	---	---	0.171	0.115	---	---	---	---	0.102	0.068	---	---	---	---
Planer Shavings Cyclone #4 BH, EU#6	0.273	0.183	---	---	---	---	0.171	0.115	---	---	---	---	0.102	0.068	---	---	---	---
Point Source Total Emissions	31.2	28.8	10.8	84	91.2	354	22.5	20.8	7.4	58	58.3	373	8.7	8.0	3.4	26	32.9	-20
Process Fugitive Sources																		
DEBARKER, PF, EU#14a	0.849	0.150	---	---	---	---	0.533	0.094	---	---	---	---	0.3160	0.0559	---	---	---	---
BARK HOG, PF, EU#14b	0.021	0.004	---	---	---	---	0.013	0.002	---	---	---	---	7.90E-03	1.40E-03	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF	0.00094	0.00013	---	---	---	---	0.0006	0.0001	---	---	---	---	3.49E-04	4.99E-05	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF	0.00938	0.00134	---	---	---	---	0.0059	0.0008	---	---	---	---	3.49E-03	4.99E-04	---	---	---	---
PLANER SHAVINGS BIN TRUCK LOADOUT, PF	0.00191	0.00027	---	---	---	---	0.0012	0.0002	---	---	---	---	7.12E-04	1.02E-04	---	---	---	---
Fugitive Sources																		
ASH HANDLING EU#16	0.7406	0.3703	---	---	---	---	0.5084	0.2542	---	---	---	---	2.32E-01	1.16E-01	---	---	---	---
HOG FUEL CONVEY/LOADOUT	0.00068	0.00010	---	---	---	---	0.0004	0.0001	---	---	---	---	2.51E-04	3.59E-05	---	---	---	---
SAWMILL SAWING, INDOOR	0.06075	0.01063	---	---	---	---	0.0381	0.0067	---	---	---	---	2.26E-02	3.96E-03	---	---	---	---
SAWMILL CHIPPER, INDOOR	0.00938	0.00164	---	---	---	---	0.0059	0.0010	---	---	---	---	3.49E-03	6.11E-04	---	---	---	---
PAVED ROADS	0.2118	0.0520	---	---	---	---	0.1329	0.0326	---	---	---	---	7.89E-02	1.94E-02	---	---	---	---
UNPAVED ROADS	0.8257	0.0826	---	---	---	---	0.5183	0.0518	---	---	---	---	3.07E-01	3.07E-02	---	---	---	---
Fugitive Totals	2.73	0.87	0.00	0.00	0.00	0.00	1.76	0.44	0.00	0.00	0.00	0.00	0.97	0.23	0.00	0.00	0.00	0.00
Plantwide Total	33.92	29.52	10.80	84.32	91.20	353.6	24.24	21.28	7.41	57.88	58.28	373.4	9.67	8.24	3.39	26.44	32.92	-19.82

Baseline HAPs are limited to 10 tpy of a single HAP and 25 tpy total HAPs.

Total HAP emissions in Baseline 2014/2016	18.66 tpy
Single highest HAP in Baseline 2014/2016	8.02 tpy
Total HAP emissions under the new proposal	29.00 tpy
Single highest HAP under the new proposal:	12.79 tpy
Proposed Board Foot Production	214,300 mbf/yr
Proposed Steaming Rate	544,000 kib/yr

Increases Comparing Proposed to Baseline, using same calculations

	PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)
Proposed PTE	33.92	29.52	10.80	84.32	91.20	353.60
Baseline Actual	24.24	21.28	7.41	57.88	58.28	373.4
PSD Threshold	9.67	8.24	3.39	26.44	32.92	-19.82
PSD Threshold	15.00	10.00	40.00	40.00	40.00	100.00
	ok	ok	ok	ok	ok	ok

**IDAHO FOREST GROUP
MOYIE SPRINGS, IDAHO
Emission Inventory/Calculations**

	Proposed PTE with Changed Conditions						Baseline PTE						Emissions Increase					
	PM10 (lb/hr)	PM2.5 (lb/hr)	SO ₂ (lb/hr)	NO _x (lb/hr)	VOCs (lb/hr)	CO (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	SO ₂ (lb/hr)	NO _x (lb/hr)	VOCs (lb/hr)	CO (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	SO ₂ (lb/hr)	NO _x (lb/hr)	VOCs (lb/hr)	CO (lb/hr)
Point Sources																		
KIPPER & SONS HOG FUEL BOILER, EU#1	6.86	6.86	3.18	24.8	4.95	104.0	6.51	6.51	3.18	24.80	4.55	104.00	0.3502	0.3502	0.0000	0.0000	0.0000	0.0000
EFB MEDIA BAGHOUSE EU#2	0.00	0.00	---	---	---	---	0.18	0.12	---	---	---	---	-0.1800	-0.1206	---	---	---	---
LUMBER DRY KILNS, EU#7	1.44	1.25	---	---	26.37	---	1.44	1.25	---	26.37	---	---	0.0000	0.0000	---	---	0.0000	---
Fuel Bin #1 and #2 Target Boxes, EU#8 and EU#9	0.308	0.154	---	---	---	---	0.308	0.154	---	---	---	---	0.0000	0.0000	---	---	---	---
Hog Fuel Truck Bin TB, EY#10, 10% of hog fuel	0.034	0.017	---	---	---	---	0.034	0.017	---	---	---	---	0.0000	0.0000	---	---	---	---
Sawdust Truck Bin Target Box, EU#11	0.238	0.119	---	---	---	---	0.238	0.119	---	---	---	---	0.0000	0.0000	---	---	---	---
Chip Cyclone #2, EU#4	0.095	0.048	---	---	---	---	0.095	0.048	---	---	---	---	0.0000	0.0000	---	---	---	---
Green Chip Bin Target Box, EU#12	0.428	0.214	---	---	---	---	0.428	0.214	---	---	---	---	0.0000	0.0000	---	---	---	---
Planer Shavings Cyclone #3 BH, EU#5	0.097	0.065	---	---	---	---	0.097	0.065	---	---	---	---	0.0000	0.0000	---	---	---	---
Planer Shavings Cyclone #4 BH, EU#6	0.097	0.065	---	---	---	---	0.097	0.065	---	---	---	---	0.0000	0.0000	---	---	---	---
Point Source Total Emissions:	9.60	8.90	3.2	25	31.3	104	9.43	8.57	3.2	25	31.3	104	0.1702	0.2296	0.0000	0.0000	0.0000	0.0000
Process Fugitive Sources																		
DEBARKER, PF, EU#14a	3.01E-01	5.33E-02	---	---	---	---	3.01E-01	5.33E-02	---	---	---	---	0.0000	0.0000	---	---	---	---
BARK HOG, PF, EU#14b	7.52E-03	1.33E-03	---	---	---	---	7.52E-03	1.33E-03	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF	3.33E-04	4.75E-05	---	---	---	---	3.33E-04	4.75E-05	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF	3.33E-03	4.75E-04	---	---	---	---	3.33E-03	4.75E-04	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
PLANER SHAVINGS BIN TRUCK LOADOUT, PF	6.78E-04	9.69E-05	---	---	---	---	6.78E-04	9.69E-05	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
Fugitive Sources																		
ASH HANDLING EU#16	1.69E-01	8.45E-02	---	---	---	---	1.69E-01	8.45E-02	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
HOG FUEL CONVEY/LOADOUT	2.39E-04	3.42E-05	---	---	---	---	2.39E-04	3.42E-05	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
SAWMILL SAWING, INDOOR	2.15E-02	3.77E-03	---	---	---	---	2.15E-02	3.77E-03	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
SAWMILL CHIPPER, INDOOR	3.33E-03	5.82E-04	---	---	---	---	3.33E-03	5.82E-04	---	---	---	---	0.00E+00	0.00E+00	---	---	---	---
PAVED ROADS	4.84E-02	1.19E-02	---	---	---	---	3.04E-02	7.45E-03	---	---	---	---	1.80E-02	4.42E-03	---	---	---	---
UNPAVED ROADS	1.89E-01	1.89E-02	---	---	---	---	1.18E-01	1.16E-02	---	---	---	---	7.02E-02	7.02E-03	---	---	---	---
Fugitive Totals	0.74	0.17	0.00	0.00	0.00	0.00	0.66	0.16	0.00	0.00	0.00	0.00	0.09	0.01	0.00	0.00	0.00	0.00
Plantwide Total	10.34	8.97	3.2	24.8	31.3	104.0	10.09	8.73	3.2	24.8	31.3	104.0						

IDAHO FOREST GROUP -- Moyie Springs
Emission Inventory/Calculations
 Baseline Based on 2014/2016

PROPOSED PERMIT LIMITED PRODUCTION

Lumber Production

Sawmill Production	214,300	mbdft/year	Limited by kiln
Dry Kiln Production	214,300	mbdft/year	Limited by VOC PSD-avoidance limit
Planer Production	214,300	mbdft/year	Limited by kiln
Logs Used	771,480	tons/year (estimate)	

Boiler Steam Production	544,000	klb/yr	Proposed PSD-avoidance limit
Boiler Heat Input	863,872	mmBtu/yr	Based on steam and efficiency

Residuals Production	Green Wt. tons/year	Dry wt. BDT/year	Estimation Factor	
Sawmill Chips	107,150	53,575	1000	lb chips/mbdft sawmill
Sawdust	53,575	26,788	500	lb sawdust/mbdft sawmill
Hog Bark	77,148	38,574	200	lb bark/ton logs
Shavings	32,145	27,323	300	lb shavings/mbdft planer

Ratios based on data from IFG mills

BASELINE 2014/2016 - PRODUCTION

Lumber Production

Sawmill Production	134,492	mbdft/year	PTE
Dry Kiln Production	134,492	mbdft/year	PTE
Planer Production	134,492	mbdft/year	PTE
Logs Used	484,171	tons/year (estimate)	

Boiler Steam Production	373,422	klb/yr	Baseline PSD-avoidance limit
Boiler Heat Input	592,994	mmBtu/yr	Based on steam and efficiency

Residuals Production	Green Wt. tons/year	Dry wt. BDT/year	Estimation Factor	
Sawmill Chips	67,246	33,623	1000	lb chips/mbdft sawmill
Sawdust	33,623	16,812	500	lb sawdust/mbdft sawmill
Hog Bark	48,417	24,209	200	lb bark/ton logs
Shavings	20,174	17,148	300	lb shavings/mbdft planer

Ratios based on site data

**Residuals Production, 24-hour peak
 Max Hourly Prod.**

	38	Based on 38 mbf/hr, 912 mbf/day			
	Green Wt. ton/hr	Dry wt. BDT/hr	Estimation Factor		
Sawmill Chips	19	9.50	1000	lb chips/mbdft sawmill	50% moisture
Sawdust	10	4.75	500	lb sawdust/mbdft sawmill	50% moisture
Hog Bark	13.7	6.84	200	lb bark/ton logs	50% moisture
Shavings	5.7	4.85	300	lb shavings/mbdft planer	15% moisture
Logs	137				

KIPPER & SONS HOG FUEL BOILER, EU#1

Hours of operation	8,760 Hours/Year, PTE
Max Design Steaming Rate	80,000 lb steam/hr, boiler max
Max. Design Heat Input	127 mmBtu/hr maximum
Baseline Steam	373,422 klb steam/yr, Baseline permit limit
Baseline Heat Input	592,994 mmBtu/yr, PTE (based on 75% eff.)
Proposed Allowable Steam	544,000 klb steam/yr, proposed permit limit
Proposed Allowable Heat Input	863,872 mmBtu/yr, PTE (based on 75% eff.)

Baseline PM10/PM2.5, based on permit limits

Permitted Hourly Emissions	6.51 lb/hr	Current Permit Limit
Permitted Annual Emissions	28.5 tons/year	Current Permit Limit

Baseline and proposed PM10/PM2.5, based on proposed emission factor

Emission Factor:	0.054 lb/MMBtu	Boiler MACT filterable limit + condensible fraction
Hourly Emissions	6.86 lb/hr	Proposed Permit Limit
Baseline Annual Emissions	17.01 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	23.32 tons/year	Calculated Annual Emissions based on emission factor

Sulfur Dioxide, Baseline and proposed

Emission Factor:	0.025 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Baseline and Proposed hourly	3.18 lb/hr	Peak 1-hour emission rate, unchanged
Baseline annual emissions	7.41 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	10.80 tons/year	Annual emissions limited by proposed steaming limit

NOx, Baseline and proposed

Emission Factor:	0.31 lb/klb steam	Old AP-42 factor, converts to 0.2 lb/MMBtu
Baseline and Proposed hourly	24.80 lb/hr	Peak 1-hour emission rate, unchanged
Baseline annual emissions	57.88 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	84.32 tons/year	Annual emissions limited by proposed steaming limit

VOC, Baseline and proposed

Emission Factor:	0.039 lb/mmBtu	AP-42 Emission Factor for TOC (TOC > VOC)
Baseline and Proposed hourly	4.95 lb/hr	Peak 1-hour emission rate, unchanged
Baseline annual emissions	11.56 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	16.85 tons/year	Annual emissions limited by proposed steaming limit

CO, Baseline and proposed

Emission Factor:	1.3 lb/klb steam	Conservative value, supported by July 2016 source test
Baseline and Proposed hourly	104.00 lb/hr	Peak 1-hour emission rate, unchanged
Baseline annual emissions	373.42 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	353.60 tons/year	Annual emissions limited by proposed steaming limit

EFB MEDIA BAGHOUSE EU#2

Removed after ESP Installed

Hours of operation 8,760 Hours/Year, PTE
Design flow rate 4,200 dscfm Baghouse design flow.

PM/PM10:

Emission Factor: 0.005 gr/dscf Baghouse design emission rate.
Proposed Annual 0.00 tpy
Baseline Annual 0.54 tpy
Baseline hourly 0.180 lb/hr Permit Limit

PM2.5 :

Emission Factor: 0.00335 gr/dscf PM2.5 is 67% of PM10
Proposed Annual 0.00 tpy for baghouse. Based on DEQ
Baseline Annual 0.36 tpy For modeling
Baseline hourly 0.121 lb/hr PM2.5 is 67% of PM10

ASH HANDLING EU#16

Assume PM10 is 100% of PM

Ash in fuel, based on fuel analysis: 1.6% by wet weight
Proposed 926 1.2% of hog by weight, tons of ash/year
Baseline 775 1.2% of hog by weight, tons of ash/year

PM/PM10:

Emission Factor: 1.6 lbs/ton Factor from original Tier I Application
Proposed Annual 0.7406 tpy
Baseline and Proposed hourly 0.17 lb/hr
Baseline Annual 0.51 tpy

PM2.5 :

Emission Factor: 0.8 lbs/ton Assume PM2.5 is 50% of PM10
Proposed Annual 0.37 tpy
Baseline and Proposed hourly 0.08 lb/hr
Baseline Annual 0.25 tpy

MACT Emission Limits, based on January 31, 2013 version of Boiler MACT. Effective Jan. 1, 2017

Particulate Matter, filterable

Emissions: 0.037 lb/mmBtu heat input Table 2 to Subpart DDDDD of Part 63
15.98 tons/year 7. Stokers designed to burn wet biomass fuel
4.70 lbs/hr

Carbon Monoxide (CO)

Emissions: 1500 ppm @ 3% oxygen Table 2 to Subpart DDDDD of Part 63
1,219,584 dscf/hr, flue gas @ 0% oxygen Based on F-Factor for wood bark
1,423,984 dscf/hr, flue gas @ 3% oxygen Adjusted to 3% oxygen
3,753 lbmol/hr, flue gas @ 3% oxygen 379.4 dscf/lbmol At 60°F and 1 atm.
5.63 lbmol/hr CO 1500 ppm CO
157.7 lb/hr CO M.W. = 28.01 lb/lbmol
691 tpy CO

LUMBER DRY KILNS, EU#7

Baseline Permit Limit: 134,492 mbdft/yr, lumber dried
 Proposed Permit Limit: 214,300 mbdft/yr, lumber dried
 Peak hours of operation: 8,760 kilns can run 7 days a week

CRITERIA POLLUTANTS

PM/PM10

Emission Factor:	0.038 lbs/mbdft	Factor based on kiln PM test
Baseline and proposed max hourly	1.444 lb/hr	Based on 38 mbf/hr, 912 mbf/day
Baseline and proposed max daily	34.7 lb/day	Permit limit is 34.8 lb/day
Baseline annual emissions	2.56 tpy	Baseline annual using modern emission factor
Proposed annual emissions	4.07 tpy	Proposed annual using modern emission factor

PM25

Emission Factor:	0.033 lbs/mbdft	Factor based on kiln PM test
Baseline and proposed max hourly	1.25 lb/hr	Based on 38 mbf/hr, 912 mbf/day
Baseline annual emissions	2.22 tpy	Baseline annual using modern emission factor
Proposed annual emissions	3.54 tpy	Proposed annual using modern emission factor

VOC:

Emission Factor:	0.694 lbs/1000 bd.ft.	
Baseline annual emissions	46.72 tons/year	Baseline Actuals, Baseline Emissions Spreadsheet
Proposed annual emissions	74.35 tons/year	Proposed annual using modern emission factor
Baseline and proposed max hourly	26.37 lb/hr	

HAZARDOUS AIR POLLUTANTS

Total HAP

Emission Factor:	0.197 lbs/1000 bd.ft.	P-2012.0034 Table 4.3
Baseline annual emissions	13.25 tons/year	HAP Emissions based on
Proposed annual emissions	21.12 tons/year	mix shown below.

Methanol, highest single HAP

Methanol, highest single HAP

Emission Factor:	0.119 lbs/1000 bd.ft.	P-2012.0034 Table 4.3
Baseline annual emissions	8.02 tons/year	Single HAP Emissions based on
Proposed annual emissions	12.79 tons/year	mix shown below.

Wood Species, representative:

	% of Total	VOC (lb/MBdft)	Weighted (lb/Mbdft)	Total HAP (lb/MBdft)	Weighted (lb/Mbdft)	Methanol (lb/MBdft)	Weighted (lb/Mbdft)	
Ponderosa Pine	0.34%	2.46	0.01	0.148	0.00	0.102	0.000	P-2012.0034 Table 4.3
Douglas Fir	25.80%	1.03	0.27	0.171	0.04	0.096	0.025	P-2012.0034 Table 4.3
Larch	14.90%	0.25	0.04	0.291	0.04	0.187	0.028	P-2012.0034 Table 4.3
Hemlock	15.50%	0.24	0.04	0.243	0.04	0.133	0.021	P-2012.0034 Table 4.3
Grand (white) Fir	12.70%	0.70	0.09	0.189	0.02	0.122	0.015	P-2012.0034 Table 4.3
Hemlock, Hem-fir		0.70	0.00	0.243	0.00	0.133	0.000	P-2012.0034 Table 4.3
Lodgepole	13.70%	1.32	0.18	0.092	0.01	0.060	0.008	P-2012.0034 Table 4.3
Spruce	7.39%	0.11	0.01	0.092	0.01	0.054	0.004	P-2012.0034 Table 4.3
ESLP: Englemann Spr. Lodgepole		1.32	0.00	0.092	0.00	0.054	0.000	P-2012.0034 Table 4.3
Alpine Fir, White Fir	9.64%	0.70	0.07	0.291	0.03	0.187	0.018	P-2012.0034 Table 4.3
Cedar	0.00%	0.15	0.00	0.092	0.00	0.054	0.000	P-2012.0034 Table 4.3
Other	0.00%	2.46	0.00	0.291	0.00	0.187	0.000	P-2012.0034 Table 4.3
Total	100.0%		0.694		0.197		0.1193	

Idaho Forest Group - Moyie
Dry Kiln Haps

EMISSIONS YEAR	PTE
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* white wood is Alpine Fir, etc.

ENTER	
Total MBF processed	214,300
Ponderosa Pine	0.3%
Douglas Fir	25.8%
Larch	14.9%
Hemlock	15.5%
Grand (white) Fir	12.7%
Hemlock, Hem-fir	0.0%
Lodgepole	13.7%
Englemann Spruce	7.4%
ESLP	0.0%
Alpine Fir	9.6%
Cedar	0.0%
Other	0.0%
	100%

*729 MBF/Yr by species calculated by Total MBF * % species*

55,289
31,931
33,217
27,216
0
29,359
15,837
0
20,659
0
0
214,236

EMISSION FACTORS:	Factors from OSU and U of I Studies, available upon request					
Pollutant	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Ponderosa Pine	0.148	0.102	0.0067	0.0334	0.0027	0.0034
Douglas Fir	0.171	0.096	0.0104	0.0627	0.0007	0.0010
Larch	0.291	0.187	0.0045	0.0840	0.0140	0.0010
Hemlock	0.243	0.133	0.0030	0.1039	0.0084	0.0018
Grand (white) Fir	0.189	0.122	0.0028	0.0627	0.0007	0.0010
Hemlock, Hem-fir	0.243	0.133	0.0030	0.1039	0.0084	0.0018
Lodgepole	0.092	0.060	0.0067	0.0334	0.0027	0.0034
Englemann Spruce	0.092	0.054	0.0032	0.1029	0.0084	0.0016
ESLP	0.092	0.054	0.0067	0.1029	0.0084	0.0034
Alpine Fir	0.291	0.187	0.0045	0.0840	0.0140	0.0019
Cedar	0.092	0.054	0.0030	0.0333	0.0005	0.0008
Other	0.291	0.187	0.0045	0.0840	0.0140	0.0019

EMISSIONS

Emission lb/Yr

Species	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Ponderosa Pine	108	74	5	24	2	2
Douglas Fir	9453	5320	574	3467	38	53
Larch	9305	5971	144	2682	447	31
Hemlock	8072	4411	101	3452	279	61
Grand (white) Fir	5144	3320	76	1706	19	27
Hemlock, Hem-fir	0	0	0	0	0	0
Lodgepole	2701	1762	197	980	79	100
Englemann Spruce	1457	855	50	1629	133	25
ESLP	0	0	0	0	0	0
Alpine Fir	6012	3863	93	1735	289	39
Cedar	0	0	0	0	0	0
Other	0	0	0	0	0	0
TOTAL, lb/yr	42,251	25,576	1,240	15,677	1,287	339
TOTAL, ton/yr	21.13	12.79	0.62	7.84	0.64	0.17

CYCLONE AND BAGHOUSE PTE EMISSIONS

Source	PM ef (lb/BDT)	PM10 ef (lb/BDT)	PM2.5 ef (lb/BDT)	reference
Fuel Bin #1 and #2 Target Boxes, EU#8 and EU#9	0.1	0.050	0.025	ODEQ AQ-EF02
Hog Fuel Truck Bin TB, EU#10, 10% of hog fuel	0.1	0.050	0.025	ODEQ AQ-EF02
Sawdust Truck Bin Target Box, EU#11	0.1	0.050	0.025	ODEQ AQ-EF02
Chip Cyclone #2, EU#4	0.2	0.100	0.050	ODEQ AQ-EF02
Green Chip Bin Target Box, EU#12	0.1	0.050	0.025	ODEQ AQ-EF02
Planer Shavings Cyclone #3 BH, EU#5	0.040	0.040	0.027	ODEQ AQ-EF02 ⁽¹⁾
Planer Shavings Cyclone #4 BH, EU#6	0.040	0.040	0.027	ODEQ AQ-EF02 ⁽¹⁾

(1) DEQ determined that baghouse PM2.5 should be calculated as 67% of PM10 and cyclone PM2.5 should be calculated as 50% of PM10.

Source	Basis	Production Units	Baseline Actual					Basis	Production Units	Proposed PTE				
			PM10 (ton/yr)	Daily PM10 (lb/hr)	PM2.5 (ton/yr)	PM2.5 (lb/hr)	PM (ton/yr)			PM10 (ton/yr)	Daily PM10 (lb/hr)	PM2.5 (ton/yr)	PM2.5 (lb/hr)	PM (ton/yr)
Fuel Bin #1 and #2 Target Boxes, EU#8 and EU#9 90% of hog fuel	21,788	BDT/yr	0.5447		0.2723		1.0894	34,717	BDT/yr	0.8679		0.4340		1.7358
	6.2	BDT/hr		0.3078		0.1539		6.2	BDT/hr		0.3078		0.1539	
Hog Fuel Truck Bin TB, EY#10, 10% of hog fuel	2,421	BDT/yr	0.0605		0.0303		0.1210	3,857	BDT/yr	0.0964		0.0482		0.1929
	0.68	BDT/hr		0.0342		0.0171		0.68	BDT/hr		0.0342		0.0171	
Sawdust Truck Bin Target Box, EU#11	16,812	BDT/yr	0.4203		0.2101		0.8406	26,788	BDT/yr	0.6697		0.3348		1.3394
	4.8	BDT/hr		0.2375		0.1188		4.8	BDT/hr		0.2375		0.1188	
Chip Cyclone #2, EU#4 10% of Chips	3,362	BDT/yr	0.1681		0.0841		0.3362	5,358	BDT/yr	0.2679		0.1339		0.5358
	1.0	BDT/hr		0.0950		0.0475		1.0	BDT/hr		0.0950		0.0475	
Green Chip Bin Target Box, EU#12	33,623	BDT/yr	0.8406		0.4203		1.6812	53,575	BDT/yr	1.3394		0.6697		2.6788
	8.6	BDT/hr		0.4275		0.2138		8.6	BDT/hr		0.4275		0.2138	
Planer Shavings Cyclone #3 BH, EU#5	8,574	BDT/yr	0.1715		0.1149		0.1715	13,662	BDT/yr	0.2732		0.1831		0.2732
	2.4	BDT/hr		0.0969		0.0649		2.4	BDT/hr		0.0969		0.0649	
Planer Shavings Cyclone #4 BH, EU#6	8,574	BDT/yr	0.1715		0.1149		0.1715	13,662	BDT/yr	0.2732		0.1831		0.2732
	2.4	BDT/hr		0.09690		0.06492		2.4	BDT/hr		0.0969		0.0649	

Conversion of minutes to hours	60 min/hr
Conversion of grains to lbs	7000 gr/lb

MILL FUGITIVE SOURCES

Emission Factors

Fugitive Emissions Source	PM ef	PM10 ef	PM2.5 ef	Units	Control Eff.	Emission Factor Reference
DEBARKER, PF, EU#14a	0.02	0.011	0.001947	lb/ton logs	80%	AIRS 3-07-008-01, NCASI for PM2.5% 80% control for partial enclosure
BARK HOG, PF, EU#14b	0.02	0.011	0.001947	lb/BDT bark	90%	AIRS 3-07-008-01, NCASI for PM2.5% 90% control for full enclosure
HOG FUEL CONVEY/LOADOUT	0.00075	0.00035	0.00005	lb/BDT bark	90%	FARR drop factor "wet", 90% for enclosure
SAWMILL SAWING, INDOOR	0.35	0.175	0.030625	lb/ton logs, less bark weight	99.9%	FARR PM10 sawing factor, NCASI PM2.5%, 99.9% control indoors (FARR uses 100%),
SAWMILL CHIPPER, INDOOR	0.35	0.175	0.030625	lb/tons chips	99.9%	Use sawing factor
SAWDUST BIN TRUCK LOADOUT, PF	0.00075	0.00035	0.00005	lb/BDT sawdust	80%	FARR drop factor "wet", 80% control for side panels
CHIP BIN TRUCK LOADOUT, PF	0.00075	0.00035	0.00005	lb/BDT chips	0%	FARR drop factor "wet",
PLANER SHAVINGS BIN TRUCK LOADOUT, PF	0.0015	0.0007	0.0001	lb/BDT shavings	80%	FARR drop factor "dry", 80% control for sides panels

Annual Permitted Emissions

Fugitive Emissions Source	Proposed			Baseline		
	PM tpy	PM10 tpy	PM2.5 tpy	PM tpy	PM10 tpy	PM2.5 tpy
DEBARKER, PF, EU#14a	1.54296	0.848628	0.1502072	0.9683424	0.53258832	0.094268133
BARK HOG, PF, EU#14b	0.039	0.021	0.004	0.024	0.013	0.002
HOG FUEL CONVEY/LOADOUT	0.001	6.75E-04	9.64E-05	0.001	4.24E-04	6.05E-05
SAWMILL SAWING, INDOOR	1.22E-01	6.08E-02	1.06E-02	7.63E-02	3.81E-02	6.67E-03
SAWMILL CHIPPER, INDOOR	1.88E-02	9.38E-03	1.64E-03	1.18E-02	5.88E-03	1.03E-03
SAWDUST BIN TRUCK LOADOUT, PF	2.01E-03	9.38E-04	1.34E-04	1.26E-03	5.88E-04	8.41E-05
CHIP BIN TRUCK LOADOUT, PF	2.01E-02	9.38E-03	1.34E-03	1.26E-02	5.88E-03	8.41E-04
PLANER SHAVINGS BIN TRUCK LOADOUT, PF	4.10E-03	1.91E-03	2.73E-04	2.57E-03	1.20E-03	1.71E-04

24-hour Permitted Emissions

Fugitive Emissions Source	Proposed			Baseline		
	PM lb/hr	PM10 lb/hr	PM2.5 lb/hr	PM lb/hr	PM10 lb/hr	PM2.5 lb/hr
DEBARKER, PF, EU#14a	0.55	0.30	0.05	0.55	0.30	0.05
BARK HOG, PF, EU#14b	0.014	0.008	1.332E-03	0.014	0.008	1.332E-03
HOG FUEL CONVEY/LOADOUT	5.13E-04	2.39E-04	3.42E-05	5.13E-04	2.39E-04	3.42E-05
SAWMILL SAWING, INDOOR	4.31E-02	2.15E-02	3.77E-03	4.31E-02	2.15E-02	3.77E-03
SAWMILL CHIPPER, INDOOR	6.65E-03	3.33E-03	5.82E-04	6.65E-03	3.33E-03	5.82E-04
SAWDUST BIN TRUCK LOADOUT, PF	7.13E-04	3.33E-04	4.75E-05	7.13E-04	3.33E-04	4.75E-05
CHIP BIN TRUCK LOADOUT, PF	7.13E-03	3.33E-03	4.75E-04	3.56E-03	3.33E-03	4.75E-04
PLANER SHAVINGS BIN TRUCK LOADOUT, PF	1.45E-03	6.78E-04	9.69E-05	1.45E-03	6.78E-04	9.69E-05

NCASI Special Report No. 15-01, Table 6.1 Average Total Potential Filterable PM10 and PM2.5 for Chips and Bark

Fresh Wood Chips
 Fresh Bark
 Hogged Bark

17.5% PM2.5 portion of PM10 emissions
 17.7% PM2.5 portion of PM10 emissions
 15.4% PM2.5 portion of PM10 emissions

Fugitive Road Dust, EU#15

Calculations based on AP-42 Section 13.2.1, rev. 11/06

PAVED ROADS

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VMT per Year	Avg. Vehicle Weight W	Weighted Vehicle Weight
Log Trucks	Paved, Loaded	14,287	0.30	4,286	40.0	4.0
	Paved, Empty	14,287	0.30	4,286	13.0	1.3
Chip Trucks	Paved, Loaded	3,986	0.15	598	40.0	0.6
	Paved, Empty	3,986	0.15	598	13.0	0.2
Shavings Trucks	Paved, Loaded	1,410	0.28	401	36.0	0.3
	Paved, Empty	1,410	0.28	401	13.0	0.1
Sawdust Trucks	Paved, Loaded	1,993	0.19	377	40.0	0.4
	Paved, Empty	1,993	0.19	377	13.0	0.1
Lumber Trucks	Paved, Loaded	14,287	0.28	4,059	40.0	3.8
	Paved, Empty	14,287	0.28	4,059	13.0	1.2
Forklifts	Paved, Loaded	428,600	0.02	8,572	3.0	0.6
	Paved, Empty	428,600	0.02	8,572	1.0	0.2
Misc. Vehicles incl employee	Paved	62,400	0.10	6,240	1.0	0.1
		991,525		42,825		12.9

$$E = k(sL)^{0.91}(W)^{1.02} * [1 - 1.2 * P/N]$$

	PM	PM10	PM2.5	P=	P=	120
k =	0.011	0.0022	0.00054	N=	N=	365
sL =	1.1	1.1	1.1			
W =	13	13	13			
E =	0.099	0.020	0.005			

% control from washing/sw.	lb/VMT	lb/VMT	lb/VMT
	50%	50%	50%

Total PM Emissions:	1.1	tpy
Total PM10 Emissions:	0.21	tpy
Total PM2.5 Emissions:	0.05	tpy

Proposed and Baseline Hourly

Total PM Emissions:	0.28	lb/hr
Total PM10 Emissions:	0.06	lb/hr
Total PM2.5 Emissions:	0.01	lb/hr

Fugitive Road Dust, EU#15

Calculations based on AP-42 Section 13.2.2, rev. 12/06

UNPAVED ROADS

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VMT per Year	Avg. Vehicle Weight W	Weighted Vehicle Weight
Log Trucks	Unpaved, Loaded	14,287	0.20	2,857	40.0	8.0
	Unpaved, Empty	14,287	0.20	2,857	13.0	2.6
Chip Trucks	Unpaved, Loaded	3,986	0.00	0	40.0	0.0
	Unpaved, Empty	3,986	0.03	114	13.0	0.1
Shavings Trucks	Unpaved, Loaded	1,410	0.03	40	36.0	0.1
	Unpaved, Empty	1,410	0.00	0	13.0	0.0
Sawdust Trucks	Unpaved, Loaded	1,993	0.00	0	40.0	0.0
	Unpaved, Empty	1,993	0.00	0	13.0	0.0
Lumber Trucks	Unpaved, Loaded	14,287	0.00	0	40.0	0.0
	Unpaved, Empty	14,287	0.03	407	13.0	0.4
988 Mill Feed	Unpaved, Loaded	14,287	0.10	1,429	40.0	4.0
	Unpaved, Empty	14,287	0.10	1,429	13.0	1.3
Log Loaders	Unpaved, Loaded	25,716	0.10	2,572	25.0	4.5
	Unpaved, Empty	25,716	0.10	2,572	15.0	2.7
Misc. Vehicles incl employee	Unpaved	62,400	0.00	0	1.0	0.0
		214,330		14,276		23.7

$$E = [k(s/12)^a(w/3)^b] * (365-P)/365$$

	PM	PM10	PM2.5	P=	120
k =	4.9	1.5	0.15		
s =	1.8	1.8	1.8		
W =	24	24	24		
a =	0.7	0.9	0.9		
b =	0.45	0.45	0.45		

Uncontrolled E= 2.209 lb/VMT 0.463 lb/VMT 0.046 lb/VMT

Controlled E= 0.552 lb/VMT 0.116 lb/VMT 0.012 lb/VMT
From AP-42

Total PM Emissions:	3.9	tpy
Total PM10 Emissions:	0.83	tpy
Total PM2.5 Emissions:	0.08	tpy

IFG Moyie
Greenhouse Gas Calculations, Potential to Emit, Proposed

Hog Fuel Boiler	863,872 MMBtu/year	
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)		
Emission Factor:	93.8 kg/mmbtu	40CFR98 Table C-1
Mass Emission Rate	89,134 tpy	
Global Warming Potential:	1	40CFR98 Table A -1
Emissions:	81,031 metric tons CO2e	
Methane (CH4)		
Emission Factor:	7.20E-03 kg/mmbtu	40CFR98 Table C-2
Mass Emission Rate	6.84 tpy	
Global Warming Potential:	25	40CFR98 Table A -1
Emissions:	155 metric tons CO2e	
Nitrous Oxide (N2O)		
Emission Factor:	3.60E-03 kg/mmbtu	40CFR98 Table C-2
Mass Emission Rate	3.42 tpy	
Global Warming Potential:	298	40CFR98 Table A -1
Emissions:	927 metric tons CO2e	
Total GHG Emissions:	89,145 tpy	
Metric Tons CO2e	1,082 metric tons CO2e	

IFG Moyie
Greenhouse Gas Calculations, Baseline Actual

Hog Fuel Boiler	592,994 MMBtu/year	
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)		
Emission Factor:	93.8 kg/mmbtu	40CFR98 Table C-1
Mass Emission Rate	61,185 tpy	
Global Warming Potential:	1	40CFR98 Table A -1
Emissions:	55,623 metric tons CO2e	
Methane (CH4)		
Emission Factor:	7.20E-03 kg/mmbtu	40CFR98 Table C-2
Mass Emission Rate	4.70 tpy	
Global Warming Potential:	25	40CFR98 Table A -1
Emissions:	107 metric tons CO2e	
Nitrous Oxide (N2O)		
Emission Factor:	3.60E-03 kg/mmbtu	40CFR98 Table C-2
Mass Emission Rate	2.35 tpy	
Global Warming Potential:	298	40CFR98 Table A -1
Emissions:	636 metric tons CO2e	
Total GHG Emissions:	61,192 tpy	
Metric Tons CO2e	743 metric tons CO2e	
Changes		
CO2	27,949 tpy	
CH4	2.15 tpy	
N2O	1.07 tpy	
CO2e	339 metric tons CO2e	
Total	27952 tpy	

Mobile Sources Fugitive Dust - SUMMARY
Based on Production, for Emissions Estimation Only

Truck Schedule

Log Trucks	771,480 tons logs/yr 27 tons/truck 28,573 log trucks/yr
Chip Trucks	107,150 tons chips/yr 3,360 lb/unit 16 units/truck 3,986 chip trucks/yr
Shavings Trucks	32,145 tons shavings/yr 2,400 lb/unit 19 units/truck 1,410 shavings trucks/yr
Sawdust Trucks	53,575 units sawdust/yr 3,360 lb/unit 16 units/truck 1,993 sawdust trucks/yr
Lumber Trucks	214,300 mbdft/yr 15,000 bdf/truck 14,287 lumber trucks/yr
988 Mill Feed	385,740 tons logs/yr 27 tons/trip 14,287 trips/yr
Log Loaders	385,740 tons logs/yr 15 tons/trip 25,716 trips/yr
Fork Lifts	214,300 mbdft/yr 500 bdf/load 428,600 fork lift trips/yr

Running 12-month Calculations
 Moyie Springs Boiler

Month	Steam Production		SO2		NOx		VOC		PM10/PM2.5		CO		Notes	
	Running 12-month		SO2 tpy 0.025 lb/mmBtu	24-month average tpy	NOx tpy 0.31 lb/klb	24-month average tpy	VOC tpy 0.039 lb/mmBtu	24-month average tpy	PM10/PM2.5 e.f. (lb/klb)	PM10 tpy	CO e.f. (lb/klb)	CO tpy		24-month average tpy
	Steam (k lb)	MMBtu												
Jan-12	275,972	438,244	5.48		42.78		8.55		0.062	8.56	2.00	275.97	CO based on 2003 source test, PM10/PM2.5 based on 12-20-2009 source test	
Feb-12	277,855	441,234	5.52		43.07		8.60		0.062	8.61	2.00	277.86		
Mar-12	278,970	443,004	5.54		43.24		8.64		0.062	8.65	2.00	278.97		
Apr-12	282,728	448,972	5.61		43.82		8.75		0.062	8.76	2.00	282.73		
May-12	282,701	448,929	5.61		43.82		8.75		0.062	8.76	2.00	282.70		
Jun-12	279,861	444,419	5.56		43.38		8.67		0.062	8.68	2.00	279.86		
Jul-12	280,658	445,685	5.57		43.50		8.69		0.062	8.70	2.00	280.66		
Aug-12	281,319	446,735	5.58		43.60		8.71		0.062	8.72	2.00	281.32		
Sep-12	284,152	451,234	5.64		44.04		8.80		0.062	8.81	2.00	284.15		
Oct-12	284,409	451,642	5.65		44.08		8.81		0.062	8.82	2.00	284.41		
Nov-12	285,843	453,919	5.67		44.31		8.85		0.062	8.86	2.00	285.84		
Dec-12	286,555	455,050	5.69		44.42		8.87		0.062	8.88	2.00	286.56		
Jan-13	288,364	457,922	5.72	5.60	44.70	43.74	8.93	8.74	0.062	8.94	2.00	288.36	282.17	
Feb-13	289,518	459,755	5.75	5.63	44.88	43.97	8.97	8.78	0.062	8.98	2.00	289.52	283.69	
Mar-13	288,707	458,467	5.73	5.63	44.75	43.99	8.94	8.79	0.062	8.95	2.00	288.71	283.84	
Apr-13	290,142	460,746	5.76	5.69	44.97	44.40	8.98	8.87	0.062	8.99	2.00	290.14	286.44	
May-13	297,116	471,821	5.90	5.75	46.05	44.94	9.20	8.98	0.062	9.21	2.00	297.12	289.91	
Jun-13	301,445	478,895	5.98	5.77	46.72	45.05	9.33	9.00	0.062	9.34	2.00	301.45	290.65	
Jul-13	303,040	481,228	6.02	5.79	46.97	45.24	9.38	9.04	0.062	9.39	2.00	303.04	291.85	
Aug-13	306,199	486,244	6.08	5.83	47.46	45.53	9.48	9.10	0.062	9.49	2.00	306.20	293.76	
Sep-13	312,343	496,001	6.20	5.92	48.41	46.23	9.67	9.24	0.062	9.68	2.00	312.34	298.25	
Oct-13	322,520	512,162	6.40	6.02	49.99	47.04	9.99	9.40	0.062	10.00	2.00	322.52	303.46	
Nov-13	327,965	520,808	6.51	6.09	50.83	47.57	10.16	9.50	0.062	10.17	2.00	327.97	306.90	
Dec-13	334,462	531,126	6.64	6.16	51.84	48.13	10.36	9.62	0.062	10.37	2.00	334.46	310.51	
Jan-14	338,347	537,295	6.72	6.22	52.44	48.57	10.48	9.70	0.062	10.49	2.00	338.35	313.36	
Feb-14	342,551	543,971	6.80	6.27	53.10	48.99	10.61	9.79	0.062	10.62	2.00	342.55	316.03	
Mar-14	347,856	552,395	6.90	6.32	53.92	49.33	10.77	9.86	0.062	10.78	2.00	347.86	318.28	
Apr-14	349,317	554,715	6.93	6.35	54.14	49.56	10.82	9.90	0.062	10.83	2.00	349.32	319.73	
May-14	351,211	557,723	6.97	6.43	54.44	50.25	10.88	10.04	0.062	10.89	2.00	351.21	324.16	
Jun-14	356,314	565,827	7.07	6.53	55.23	50.98	11.03	10.18	0.062	11.05	2.00	356.31	328.88	
Jul-14	359,921	571,555	7.14	6.58	55.79	51.38	11.15	10.26	0.062	11.16	2.00	359.92	331.48	
Aug-14	362,833	576,179	7.20	6.64	56.24	51.85	11.24	10.36	0.091	16.51	2.00	362.83	334.52	
Sep-14	366,509	582,016	7.28	6.74	56.81	52.61	11.35	10.51	0.091	16.88	2.00	366.51	339.43	
Oct-14	364,797	579,298	7.24	6.82	56.54	53.27	11.30	10.64	0.091	16.60	2.00	364.80	343.66	
Nov-14	366,172	581,481	7.27	6.89	56.76	53.80	11.34	10.75	0.091	16.66	2.00	366.17	347.07	
Dec-14	368,340	584,924	7.31	6.98	57.09	54.47	11.41	10.88	0.091	16.76	2.00	368.34	351.40	
Jan-15	369,894	587,392	7.34	7.03	57.33	54.89	11.45	10.97	0.091	16.83	2.00	369.89	354.12	
Feb-15	366,540	582,066	7.28	7.04	56.81	54.95	11.35	10.98	0.091	16.68	2.00	366.54	354.55	
Mar-15	368,439	585,081	7.31	7.11	57.11	55.51	11.41	11.09	0.091	16.76	2.00	368.44	358.15	
Apr-15	373,080	592,451	7.41	7.17	57.83	55.99	11.55	11.18	0.091	16.98	2.00	373.08	361.20	
May-15	370,827	588,873	7.36	7.17	57.48	55.96	11.48	11.18	0.091	16.87	2.00	370.83	361.02	
Jun-15	368,481	585,148	7.31	7.19	57.11	56.17	11.41	11.22	0.091	16.77	2.00	368.48	362.40	
Jul-15	368,686	585,473	7.32	7.23	57.15	56.47	11.42	11.28	0.091	16.78	2.00	368.69	364.30	
Aug-15	367,616	583,774	7.30	7.25	56.98	56.61	11.38	11.31	0.091	16.73	2.00	367.62	365.22	
Sep-15	360,609	572,647	7.16	7.22	55.89	56.35	11.17	11.26	0.091	16.41	2.00	360.61	363.56	
Oct-15	361,682	574,351	7.18	7.21	56.06	56.30	11.20	11.25	0.091	16.46	2.00	361.68	363.24	
Nov-15	360,116	571,864	7.15	7.21	55.82	56.29	11.15	11.25	0.091	16.39	2.00	360.12	363.14	
Dec-15	358,139	568,724	7.11	7.21	55.51	56.30	11.09	11.25	0.091	16.30	2.00	358.14	363.24	
Jan-16	360,732	572,842	7.16	7.25	55.91	56.62	11.17	11.31	0.091	16.41	2.00	360.73	365.31	
Feb-16	369,796	587,236	7.34	7.31	57.32	57.07	11.45	11.40	0.091	16.83	2.00	369.80	368.17	
Mar-16	375,718	596,640	7.46	7.39	58.24	57.67	11.63	11.52	0.091	17.10	2.00	375.72	372.08	
Apr-16	373,764	593,537	7.42	7.41	57.93	57.88	11.57	11.5634	0.091	17.01	2.00	373.76	373.42	
May-16	379,739	603,025	7.54	7.45	58.86	58.17	11.76	11.62	0.065	12.34	2.00	379.74	375.28	
Jun-16	390,337	619,855	7.75	7.53	60.50	58.81	12.09	11.75	0.065	12.69	2.00	390.34	379.41	
Jul-16	391,000	620,908	7.76	7.54	60.61	58.88	12.11	11.76	0.065	12.71	1.30	254.15	311.42	
Aug-16	391,000	620,908	7.76	7.53	60.61	58.79	12.11	11.75	0.065	12.71	1.30	254.15	310.88	
Sep-16	391,000	620,908	7.76	7.46	60.61	58.25	12.11	11.64	0.065	12.71	1.30	254.15	307.38	
Oct-16	391,000	620,908	7.76	7.47	60.61	58.33	12.11	11.65	0.065	12.71	1.30	254.15	307.92	
Nov-16	391,000	620,908	7.76	7.45	60.61	58.21	12.11	11.63	0.065	12.71	1.30	254.15	307.13	
Dec-16	391,000	620,908	7.76	7.44	60.61	58.06	12.11	11.60	0.065	12.71	1.30	254.15	306.14	
Jan-17	391,000	620,908	7.76	7.46	60.61	58.26	12.11	11.64	0.065	12.71	1.30	254.15	307.44	
Feb-17	391,000	620,908	7.76	7.55	60.61	58.96	12.11	11.78	0.065	12.71	1.30	254.15	311.97	
Mar-17	391,000	620,908	7.76	7.61	60.61	59.42	12.11	11.87	0.065	12.71	1.30	254.15	314.93	
Apr-17	391,000	620,908	7.76	7.59	60.61	59.27	12.11	11.84	0.065	12.71	1.30	254.15	313.96	
May-17	391,000	620,908	7.76	7.65	60.61	59.73	12.11	11.93	0.065	12.71	1.30	254.15	316.94	
Baseline Actual Used in Permit Analysis				7.41	57.88	11.56	373.42							
				SO2	NOx	VOC	CO							

APPENDIX B - FACILITY COMMENTS FOR DRAFT PERMIT

Facility Comment: Table 5.2 on Page 43 says the lumber throughput limit is 199 MMBF/yr. It is 214.3 MMBF/yr as per condition 5.2 on page 44.

DEQ Response: Table 5.2 has been corrected.

Facility Comment: Table 5.2 and condition 5.3 say that the hemlock limit is 107,150 MMBF/yr. That was in the PTC as well. The value should be 107.15 MMBF/yr.

DEQ Response: Both Table 5.2 and Permit Condition 5.3 have been corrected. Also, a DEQ initiated reissuance of the PTC has corrected P-2012.0034.

Facility Comment: Table 2.1, page 5, says that the ESP manufacturer is Kipper and Sons. It should say Wellons. The PTC had it right.

DEQ Response: Table 2.1 has been corrected.

Facility Comment: Condition 4.18, bottom paragraph on page 30, regarding the steam flow monitor. We believe this requirement does not apply to a steam flow monitor - it is intended for a stack gas flow monitor.

DEQ Response: After consulting with the IFG Environmental Compliance Officer, it was determined that the steam flow measurement is a differential pressure transmitter connected upstream and downstream of an orifice plate in the main steam line. Therefore 40 CFR 63 7525 (f) for pressure monitoring systems applies and has replaced 40 CFR 63 7525 (e) in Permit Condition 4.18.

APPENDIX C – 40 CFR 63 SUBPART DDDDD BREAKDOWN

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Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES
(CONTINUED)

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

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SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

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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.

The IFG-Moyie Springs Kipper and Sons hog fuel-fired boiler (128 MMBtu/hr) is subject to NESHAPS Subpart DDDDD because it is located at a major source of HAPS.

[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.

The Kipper and Sons boiler will become an affected source upon issuance of a Permit to Construct P-2012.0034 modification, which will establish IFG-Moyie Springs as a major source.

(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.

The Kipper and Sons Boiler is an existing affected source because it was installed in 1972 and has not undergone reconstruction.

(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?

There are no boilers or process heaters located at the IFG-Moyie Springs facility that are 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.

IFG-Moyie Springs will become a major source upon issuance of a Permit to Construct P-2012.0034 modification. IFG-Moyie Springs will achieve full compliance with this rule within 3 years of that date.

(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.

IFG-Moyie Springs will meet the notification requirements and schedule. See §63.7545 for compliance actions related to notifications.

(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).

The IFG-Moyie Springs boiler does not incinerate solid waste.

(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.

IFG-Moyie Springs does not own or operate an existing EGU.

(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.

The IFG-Moyie Springs boiler does not qualify for the §63.7491(i) exemption.

(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.

IFG-Moyie Springs boiler will be in the stoker/sloped grate/others designed to burn wet biomass fuel subcategory. No changes to the boiler or fuel have been made or are anticipated.

(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.

The IFG-Moyie Springs boiler is an existing boiler.

[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.

The Kipper and Sons boiler is a stoker/spreader boiler that burns hog fuel (wood-based biomass with greater than 20% moisture on an annual heat-input basis).

- (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 13 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 Tables 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 Tables 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 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 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 (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

IFG-Moyie Springs will comply with the applicable emission limits and work practice standards for the Kipper and Sons boiler. The specific emission limits and work practice standards are identified in Tables 2 and 3, respectively.

(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 1 or 11 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 1 or 12 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 1 or 13 to this subpart until January 31, 2016.

(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).

IFG-Moyie Springs will comply with the applicable operating limits in Table 4 for the boiler. Specifically, row 4 of Table 4 applies to the electrostatic precipitator (ESP) that IFG-Moyie Springs will install to comply with this subpart, and rows 7 (operating load) and 8 (combustion oxygen level) also apply.

(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.

IFG-Moyie Springs will operate the boiler and emission controls as required.

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

IFG-Moyie Springs does not anticipate requesting approval of any alternatives to the work practice standards.

(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 11 through 13 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.

IFG-Moyie Springs does not have any limited-use boilers or process heaters.

(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.

The IFG-Moyie Springs boiler has a heat input capacity of 128 MMBtu/hr.

(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 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

The IFG-Moyie Springs boiler does not burn gaseous fuels.

(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.

IFG-Moyie Springs is cognizant and will comply.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

§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).

IFG-Moyie Springs will comply as required.

(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), 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 Tables 1, 2, or 11 through 13 to this subpart.

IFG-Moyie Springs will conduct performance stack testing to demonstrate compliance with emission limits. IFG-Moyie Springs will also operate a COMS, an oxygen analyzer, and a steam load monitor as continuous monitoring systems.

(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).

IFG-Moyie Springs will develop the required site-specific monitoring plan for the equipment used for compliance monitoring (COMS, oxygen analyzer, steam load) according to this section.

(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.

IFG-Moyie Springs will choose a definition of startup to follow for the boiler and will write an SSP if required.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

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 Tables 1 or 2 or 11 through 13 of 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.

IFG-Moyie Springs plans to perform stack testing for PM, CO, HCl, and Hg, analyze the hog fuel for heating value, establish operating limits and conduct CMS performance evaluations for the COMS, oxygen monitor and steam flow monitor. IFG-Moyie Springs is not required to conduct fuel analysis according to §63.7521 and Table 6 because the Kipper and Sons boiler burns a single type of fuel.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 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 paragraph (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.

If IFG-Moyie Springs chooses to show compliance with HCl, Hg or TSM through fuel analysis, they will follow these requirements.

(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 Tables 1, 2, or 11 through 13 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.

IFG-Moyie Springs plans to demonstrate CO compliance with source testing. There are no plans for a CO CEMS.

(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.

IFG-Moyie Springs plans to conduct a PM source test as required.

(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.

IFG-Moyie Springs will complete initial compliance testing within 180 days of the 3-year compliance deadline after becoming a major source as described in §63.7495(c)(2). An initial tune-up and an energy assessment will be completed within 3 years of becoming a major source. IFG-Moyie Springs will become a major source upon issuance of a Permit to Construct P-2012.0034 modification.

(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. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) 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 July 29, 2016.

The IFG-Moyie Springs boiler is an existing source.

(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).

The IFG-Moyie Springs boiler is an existing source.

(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.

The IFG-Moyie Springs boiler has never burned 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.

The IFG-Moyie Springs boiler is not an EGU.

(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 to this subpart, 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.

The IFG-Moyie Springs boiler will be subject to this rule three years from the date that the facility becomes a major source. IFG-Moyie Springs will become a major source upon issuance of a Permit to Construct P-2012.0034 modification. This paragraph is not applicable.

(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.

The IFG-Moyie Springs boiler will be subject to this rule three years from the date that the facility becomes a major source and the boiler will not switch subcategories. This paragraph is not applicable.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§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.

IFG-Moyie Springs will perform performance tests according to this section, until it is such that (b) below is established.

(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 13 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.

IFG-Moyie Springs will complete subsequent performance tests on the modified schedule if concurrent test results show emissions are below established thresholds.

IFG-Moyie Springs plans to conduct stack tests for HCl and Hg. The boiler will only burn one fuel, so the maximum input level requirements are automatically met.

(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 13 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 13 to this subpart).

If IFG-Moyie Springs is testing on the modified schedule and testing shows the boiler's emissions to be above the established threshold, then IFG-Moyie Springs will resume annual performance testing.

(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.

IFG-Moyie Springs will conduct annual tune-ups per the requirements of this section.

(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 Tables 1, 2, or 11 through 13 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 one 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.

IFG-Moyie Springs acknowledges these requirements and will comply if fuel analysis is used to demonstrate Hg or HCl compliance.

(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.

IFG-Moyie Springs will submit performance test reports within the required timeframe.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 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.

IFG-Moyie Springs will conduct performance testing according to this paragraph if the boiler ceases operations such that the testing schedule must be altered.

(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.

The IFG-Moyie Springs boiler is not designed to burn light liquid.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 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).

IFG-Moyie Springs does not employ a CO CEMS.

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

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§63.7520 What stack tests and procedures must I use?

IFG-Moyie Springs will conduct performance testing as required by this section and Tables 5 and 7.

(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 13 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]

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§63.7521 What fuel analyses, fuel specification, and procedures must I use?

IFG-Moyie Springs does not plan to use fuel analysis to demonstrate compliance.

(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 13 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 one-hour 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]

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§63.7522 Can I use emissions averaging to comply with this subpart?

IFG-Moyie Springs operates only one boiler and will not demonstrate compliance by emissions averaging.

(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 to this subpart as specified in paragraph (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 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 of this section 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 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.

$$AveWeightedEmissions = 1.1 \times \frac{\sum_{i=1}^n (Er_i \times Hm_i)}{\sum_{i=1}^n Hm_i} \quad (Eq. 1a)$$

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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).

H_m = 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.

$$\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 1b})$$

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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, E_{adj}, 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.

$$\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 1c})$$

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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, E_{adj}, determined according to §63.7533 for that unit.

E_o = 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 of this section as an alternative to using Equation 1a 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 to this subpart that are in pounds per million Btu of heat input.

$$\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^n (Er \times Sm \times Cf_i) \div \sum_{i=1}^n (Sm \times Cf_i) \quad (\text{Eq. 2})$$

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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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (\text{Eq. 3a})$$

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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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 3b})$$

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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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 3c})$$

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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.

Eo = 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.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (\text{Eq. 4})$$

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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.

$$E_{avg} = \sum_{i=1}^{12} ER_i + 12 \quad (\text{Eq. 5})$$

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Where:

Eavg = 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 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 of this section.

$$E_n = \sum_{i=1}^n (EL_i \times H_i) + \sum_{i=1}^n H_i \quad (\text{Eq. 6})$$

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Where:

E_n = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

EL_i = Appropriate emission limit from Table 2 to this subpart for unit i , in units of lb/MMBtu or ppm.

H_i = 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015]

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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 Tables 1, 2, or 11 through 13 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 (or carbon dioxide (CO₂)) according to the procedures in paragraphs (a)(1) through (6) of this section.

IFG-Moyie Springs will demonstrate CO compliance through performance testing and an oxygen analyzer system on the boiler. The procedures in (a)(1) through (6) of this section do not apply because IFG-Moyie Springs does not employ a CO CEMS.

(1) Install the CO CEMS and oxygen (or CO₂) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO₂) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO₂ as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations 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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 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 paragraph (a) of this section. 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 paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 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 (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be 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 §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 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, 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.

The IFG-Moyie Springs boiler is not equipped with an oxygen trim system.

(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.

The IFG-Moyie Springs boiler is a unit designed to burn biomass and is rated at 128 MMBtu/hr, so this section is not applicable.

(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.

IFG-Moyie Springs will install and operate a COMS on the boiler stack according to the requirements in this section.

(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.

IFG-Moyie Springs will operate a steam load monitoring system and oxygen analyzer system that will meet these requirements.

(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.

The IFG-Moyie Springs boiler is not subject to an operating limit that requires use of a flow monitoring system.

(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.

The IFG-Moyie Springs boiler is not subject to an operating limit that requires the use of a pressure monitoring system.

(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.

IFG-Moyie Springs does not have an operating limit that requires pH monitoring.

(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.

The IFG-Moyie Springs boiler is not equipped with a wet scrubber.

(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.

IFG-Moyie Springs does not have an operating limit that requires sorbent injection rate monitoring.

(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.

The IFG-Moyie Springs boiler is not equipped with a baghouse.

(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 be 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.

The IFG-Moyie Springs boiler is not a limited-use boiler.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of 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 a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

The IFG-Moyie Springs will not employ Hg or HCl CEMS.

(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 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.

(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 Tables 1, 2, or 11 through 13 of 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.

The IFG-Moyie Springs does not operate an acid gas wet scrubber or a dry sorbent injection system.

(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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013; 80 FR 72810, Nov. 20, 2015]

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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.

IFG-Moyie Springs will demonstrate compliance with initial performance tests. IFG-Moyie Springs only burns a single fuel type and will not conduct a fuel analysis. The plant will also comply with requirements for the COMS to be installed.

(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).

IFG-Moyie Springs will comply with the applicable stack testing procedures of §63.7520 and the procedures for establishing operating limits in Table 7 and paragraph (b)(4) of this section to meet the operating limits of row 4.a. (ESP), row 7 (operating load), and row 8 (combustion oxygen level) of Table 4. The boiler combusts only one type of fuel, so fuel analysis is not required.

(1) You must establish the maximum chlorine fuel input (C_{input}) 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.

$$C_{input} = \sum_{i=1}^n (C_i \times Q_i) \quad (\text{Eq. 7})$$

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Where:

C_{input} = 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 ($Mercury_{input}$) 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.

$$Mercury_{input} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Eq. 8})$$

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Where:

$Mercury_{input}$ = 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 (TSM_{input}) 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.

$$TSM_{input} = \sum_{i=1}^n (TSM_i \times Q_i) \quad (\text{Eq. 9})$$

Where:

TSM_{input} = 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.

Paragraph (b)(4)(viii) below is potentially relevant to the IFG-Moyie Springs boiler.

(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.

IFG-Moyie Springs does not operate a wet acid gas scrubber.

(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.

IFG-Moyie Springs does not use a PM CPMS.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(1) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(2) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging

instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(3) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(1) through (4) of this section.

(1) Determine your instrument zero output with one of the following procedures:

(i) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(iii) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(iv) If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of this section are possible, you must use a zero output value provided by the manufacturer.

(2) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n} \sum_{i=1}^n X_i; \bar{Y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

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Where:

X_i = the PM CPMS data points for the three runs constituting the performance test,

Y_i = 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.

$$R = \frac{Y_i}{(X_i - z)} \quad (\text{Eq. 11})$$

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Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y₁ = the three run average lb/MMBtu PM concentration,

X₁ = the three run average milliamp output from your 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.

$$O_1 = z + \frac{0.75L}{R} \quad (\text{Eq. 12})$$

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Where:

O₁ = 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.

$$O_n = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

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Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_n = 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.

$$30\text{-day} = \frac{\sum_{i=1}^n H_{pvi}}{n} \quad (\text{Eq. 14})$$

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Where:

30-day = 30-day average.

H_{pvi} = 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 Tables 1, 2, or 11 through 13 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 of 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. 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 and pressure drop operating limits at the higher of the minimum values established during the performance tests.

IFG-Moyie Springs does not operate a particulate wet scrubber.

(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.)

IFG-Moyie Springs does not operate 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.

IFG-Moyie Springs does not operate a dry scrubber.

(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.

IFG-Moyie Springs does not operate an activated carbon injection system.

(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.

The IFG-Moyie Springs boiler emissions are not controlled by a baghouse.

(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.

If IFG-Moyie Springs conducts multiple performance tests, IFG-Moyie Springs will set the minimum oxygen level at the lower of the minimum values established during the performance test.

(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.

IFG-Moyie Springs does not use a SO₂ CEMS.

(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.

IFG-Moyie Springs does not plan to use fuel analysis at this time; however, IFG-Moyie Springs will comply with this section if compliance is shown through fuel analysis.

(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.

$$P_{90} = \text{mean} + (SD \times t) \quad (\text{Eq. 15})$$

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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 ($t_{0.9}$) 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.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 16})$$

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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.

$$\text{Mercury} = \sum_{i=1}^n (Hgi90 \times Qi) \quad (\text{Eq. 17})$$

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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.

Qi = 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 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 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.

$$\text{Metals} = \sum_{i=1}^n (\text{TSM}_{90i} \times Q_i) \quad (\text{Eq. 18})$$

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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.

IFG-Moyie Springs will include a signed certification with the Notification of Compliance Status regarding whether the energy assessment was completed or the maximum number of on-site technical hours (8 on-site technical labor hours according to §63.7575 definition of energy assessment) were 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).

IFG-Moyie Springs will submit the Notification of Compliance Status 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.

IFG-Moyie Springs boiler does not burn gaseous fuel.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

IFG-Moyie Springs will meet the work practice standards of Table 3: one-time energy assessment, annual tune-ups, and startup and shutdown requirements.

(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:

IFG-Moyie Springs does not use a SO₂ CEMS.

(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]

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§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

IFG-Moyie Springs will not apply efficiency credits.

(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 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: <http://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:

$$ECredits = \left(\sum_{i=1}^n EIS_{\text{actual},i} \right) + EI_{\text{baseline}} \quad (\text{Eq. 19})$$

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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_{actual} = 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 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 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 section 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 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad (\text{Eq. 20})$$

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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 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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

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CONTINUOUS COMPLIANCE REQUIREMENTS

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§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).

IFG-Moyie Springs will collect and maintain required monitoring data as according to this section and the site-specific monitoring plan.

(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.

IFG-Moyie Springs will operate the monitoring systems and collect data at all times the boiler is operating except during monitor malfunction or out of control periods and during monitor QA/QC and maintenance. IFG-Moyie Springs will make repairs and resume monitoring 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.

IFG-Moyie Springs will not use data recorded during periods of startup and shutdown, monitor malfunctions or out-of-control periods, repairs, or QA/QC activities. CMS audits and dates and duration of periods when the CMS is out of control will be recorded and made available upon request. All other collected data will be used to assess compliance.

(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.

IFG-Moyie Springs understands that failure to collect required data is a deviation of monitoring requirements. IFG-Moyie Springs also understands that monitoring results must be calculated using all valid monitoring data and that all periods in which a monitoring system is out of control must be reported in the semiannual report.

§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 13 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.

IFG-Moyie Springs will demonstrate continuous compliance with applicable emission limits in Table 2, work practice standards in Table 3, and applicable operating limits in Table 4 according to the methods specified in Table 8 and according to the paragraphs of this section as noted below.

(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.

IFG-Moyie Springs will operate the boiler in compliance with established operating limits and will confirm or reestablish operating limits during performance tests by the compliance deadline.

(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:

IFG-Moyie Springs will maintain records of fuel type and amount of fuel burned in the boiler. The boiler combusts a single fuel type as established by this regulation. The boiler will combust clean dry biomass during startups (this fuel type is not considered a different fuel type because it is only used during startup). Since IFG-Moyie Springs combusts only a single fuel type, Cl, Hg, and TSM emissions are expected to be consistent, which demonstrates compliance with (ii) of this paragraph. IFG-Moyie Springs will comply with the PM (TSM surrogate) emission limit through performance testing.

(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.

IFG-Moyie Springs will not burn a new type of fuel.

(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).

IFG-Moyie Springs will not burn a new type of fuel or fuel mixture.

(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.

IFG-Moyie Springs will not burn a new type of fuel or fuel mixture.

(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.

IFG-Moyie Springs will not burn a new type of fuel or fuel mixture.

(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.

IFG-Moyie Springs boiler emissions are not controlled by a baghouse.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

IFG-Moyie Springs will not employ a CO CEMS.

(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 Tables 1 or 2 or 11 through 13 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, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

IFG Moyie-Springs will not employ a PM CPMS or a PM CEMS.

(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.

The IFG-Moyie Springs boiler has a heat input of 128 MMBtu/hr and will conduct an annual boiler tune-up according to the requirements of this section.

(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.

The IFG-Moyie Springs boiler has a heat input capacity greater than 10 MMBtu/hr.

(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.

The IFG-Moyie Springs boiler has a heat input capacity greater than 10 MMBtu/hr and is not equipped with an oxygen trim system.

(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.

IFG-Moyie Springs will conduct timely tune-ups in accordance with this requirement.

(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.

IFG-Moyie Springs does not employ a Hg CEMS.

(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 a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

IFG-Moyie Springs does not employ a HCl CEMS.

(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.

IFG-Moyie Springs will not burn a new type of fuel or fuel mixtures.

(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.

IFG-Moyie Springs will not burn a new type of fuel.

(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.

IFG-Moyie Springs does not employ a PM CPMS.

(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 (milliamperes) 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 Tables 1 or 2 or 11 through 13 of this subpart.

IFG-Moyie Springs does not employ a PM CEMS.

(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 13 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.

IFG-Moyie Springs will report deviations from emission limits or operating limits according to the requirements of §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).

The IFG-Moyie Springs boiler is not a unit designed to burn gas 1.

(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.

IFG-Moyie Springs will meet the work practice standards of items 5 and 6 of Table 3 during startup and shutdown.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015]

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

IFG-Moyie Springs will not use emissions averaging.

(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]

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NOTIFICATION, REPORTS, AND RECORDS

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§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.

IFG-Moyie Springs will submit notifications of performance tests, quality assurance program, including submission of site-specific test plans, notification of performance evaluation of continuous monitoring systems, requests for alternative monitoring procedures or relative accuracy tests (if necessary), initial notification of when the Kipper and Sons boiler becomes subject to this rule, and notification of compliance status.

(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.

IFG-Moyie Springs will become a major source upon issuance of a Permit to Construct P-2012.0034 modification. Therefore, the boiler was not an affected source before January 31, 2013.

(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.

The IFG-Moyie Springs boiler is not a new or reconstructed source.

(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.

IFG-Moyie Springs will submit a test plan and notification of intent to conduct a performance test at least 60 days before the performance test.

(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).

IFG-Moyie Springs will submit a Notification of Compliance Status according to §63.9(h)(2)(ii) within 60 days of completion of performance testing on the Kipper and Sons boiler. The Notification of Compliance Status will contain the information specified in this section.

(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 Tables 1, 2, or 11 through 13 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.

The IFG-Moyie Springs boiler is not designed to burn gas.

(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:

IFG-Moyie Springs will not combust solid waste.

(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:

IFG-Moyie Springs will submit notification if there are any fuel or physical changes made to the boiler that would result in the applicability of a different subcategory.

(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]

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§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.

IFG-Moyie Springs will submit the compliance report in Table 9 with the Idaho Tier I Air Operating Permit semiannual reports.

(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.

IFG-Moyie Springs will submit semiannual reports with the Tier I permit reports. Tier I semiannual reports are due by July 30 and January 30.

(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.

IFG-Moyie Springs will submit semiannual reports with the Tier I permit reports. Tier I semiannual reports are due by July 30 and January 30.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

IFG-Moyie Springs will include the relevant information in this section in the semiannual compliance reports.

(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.

If a deviation from an emission limit, operating limit, or work practice standard occurs, IFG-Moyie Springs will report the following:

(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).

If a deviation from an emission limit, operating limit, and monitoring requirement occurs, or if any deviations from the site-specific monitoring plan occurs, IFG-Moyie Springs will report the following:

(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.

IFG-Moyie Springs will submit reports according to 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.

IFG-Moyie Springs will submit performance test results to EPA and IDEQ through the ERT/CEDRI/CDX within 60 days after the date of completing each performance test.

(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.

IFG-Moyie Springs does not employ any CEMS.

(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.

IFG-Moyie Springs will submit the semiannual compliance report required by Table 9 to EPA via the 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).

IFG-Moyie Springs will maintain copies of each notification and report submitted to comply with this subpart, including supporting documentation.

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

IFG-Moyie Springs will maintain records of performance tests, fuel analyses, and other compliance demonstrations and performance evaluations.

(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).

IFG-Moyie Springs will maintain records of COMS data, oxygen analyzer data, steam load data, and results of performance evaluations, calibration checks, adjustments and maintenance on these monitoring systems.

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

IFG-Moyie Springs will maintain records of COMS data recorded during performance evaluations.

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

IFG-Moyie Springs will maintain copies of superseded versions of performance evaluation plans for the COMS, oxygen analyzer and steam load monitor for five years after each revision to the plan.

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

IFG-Moyie Springs does not employ CEMS.

(5) Records of the date and time that each deviation started and stopped.

IFG-Moyie Springs will maintain records of the date and time 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.

IFG-Moyie Springs will maintain records of all monitoring data and calculated averages for opacity, operating load, and oxygen level.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 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.

IFG-Moyie Springs will maintain records of fuel type and amount of fuel used by the Kipper and Sons boiler on a monthly basis.

(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).

IFG-Moyie Springs does not combust secondary materials.

(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.

IFG-Moyie Springs will demonstrate compliance with the HCl emission limit through stack testing. Since only one type of fuel is combusted in the Kipper and Sons boiler, fuel analysis is not required (see §63.7510(a)(2) and §63.7530(a)).

(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.

IFG-Moyie Springs will demonstrate compliance with the Hg emission limit through stack testing. Since only one type of fuel is combusted in the Kipper and Sons boiler, fuel analysis is not required (see §63.7510(a)(2) and §63.7530(a)).

(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 13 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.

If IFG-Moyie Springs meets the reduced stack testing frequency thresholds, IFG-Moyie Springs will maintain records documenting that the Kipper and Sons boiler emissions met the applicability threshold for reduced testing during at least two prior consecutive stack tests. Documentation will include information that shows no changes to fuel composition or boiler or air pollution control equipment operation occurred.

(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.

IFG-Moyie Springs will maintain records of the occurrence and duration of each malfunction of the Kipper and Sons boiler, ESP, COMS, oxygen analyzer, and steam load monitor.

(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.

IFG-Moyie Springs will maintain records of actions taken during periods of malfunction to minimize emissions, including corrective actions.

(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.

IFG-Moyie Springs will demonstrate compliance with the TSM emission limit through stack testing. Since only one type of fuel is combusted in the Kipper and Sons boiler, fuel analysis is not required (see §63.7510(a)(2) and §63.7530(a)).

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

IFG-Moyie Springs will 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.

IFG-Moyie Springs will maintain records of the type and amount of fuel 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.

If IFG-Moyie Springs selects paragraph (2) of the startup definition, IFG-Moyie Springs will maintain records of the time that clean fuel combustion begins, the time when wet biomass (not a clean fuel) is first fed to the boiler, the time when useful thermal energy is first supplied, and the time when PM control is 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.

If IFG-Moyie Springs selects paragraph (2) of the startup definition, IFG-Moyie Springs will maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and hourly average COMS and oxygen analyzer data during each startup period.

(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.

If IFG-Moyie Springs selects paragraph (2) of the startup definition, IFG-Moyie Springs will maintain records of the number of ESP fields in service and 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.

IFG-Moyie Springs boiler emissions are not controlled by a baghouse.

(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.

IFG-Moyie Springs boiler emissions are not controlled by a wet scrubber.

(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.

IFG-Moyie Springs will request a variance with the PM controls requirement according to the paragraphs below if deemed necessary.

(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.

IFG-Moyie Springs does not elect to average emissions.

(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).

IFG-Moyie Springs does not elect to use efficiency credits.

(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.

The IFG-Moyie Springs Kipper and Sons boiler is not designed to burn gas.

(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.

The IFG-Moyie Springs Kipper and Sons boiler is not designed to burn gas.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015]

§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).

IFG-Moyie Springs will maintain records in a form suitable and readily available for expedition review.

(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.

IFG-Moyie Springs will maintain records for 5 years following the date of each event.

(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.

IFG-Moyie Springs will maintain required records on site for at least 2 years from the date of each event.

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.

IFG-Moyie Spring will comply with the General Provisions according to Table 10.

§63.7570 Who implements and enforces this subpart?

IFG-Moyie Springs acknowledges the implementing and enforcing authority of 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?

IFG-Moyie Springs acknowledges and understands these definitions. Key definitions are highlighted.

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.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

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

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

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

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

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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

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

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

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

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

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

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

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

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

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

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

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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

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

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

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §60.14).

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

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

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

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

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

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

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

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

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

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

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

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

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

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

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be

modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

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

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

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

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

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

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

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

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

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

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

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

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

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

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

Light liquid includes distillate oil, biodiesel, or vegetable oil.

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

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

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

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source

determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

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

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

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

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

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 or 2 of 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 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1 , S_2 , and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)} \times CFN) \quad (\text{Eq. 21})$$

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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 (2) above, 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]

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Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

Does not apply. The IFG-Moyie Springs boiler is an existing boiler.

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 . . .	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 output or 1.1E-05 ^a lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
2. Units designed to	a. Filterable	1.1E-03 lb per MMBtu of	1.1E-03 lb per	Collect a minimum of 3

burn coal/solid fossil fuel	PM (or TSM)	heat input; or (2.3E-05 lb per MMBtu of heat input)	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)	dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of	Collect a minimum of 2 dscm per run.

			steam output or 3.7E-04 lb per MWh)	
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 ^a lb per MMBtu of steam output or 1.2E-03 ^a lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of 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 solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 10-day rolling	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.

		average)		
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E + 01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 ^a lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, ^d 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 ^a lb per MMBtu of heat input	5.3E-07 ^a lb per MMBtu of steam output or 6.7E-06 ^a lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3	0.13 lb per MMBtu of steam output or 1.4	1 hr minimum sampling time.

		percent oxygen, 3-run average	lb per MWh; 3-run average	
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 ^a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 ^a lb per MMBtu of steam output or 1.6E-02 ^a lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
	d. Filterable	6.7E-03 lb per MMBtu of	1.2E-02 lb per	Collect a minimum of 3

	PM (or TSM)	heat input; or (2.1E-04 lb per MMBtu of heat input)	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)	dscm per run.
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^aIf 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.

^bIncorporated by reference, see §63.14.

^cIf 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 Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

^dAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations 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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7193, Jan. 31, 2013, as amended at 80 FR 72819, Nov. 20, 2015]

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Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters
The applicable emission limits in this table apply to the IFG-Moyie Springs Kipper and Sons boiler (Designed to burn solid fuel (item 1) and Stokers/sloped grate/others designed to burn wet biomass fuel subcategory (item 7))

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 . . .
<u>1. Units in all subcategories</u>	<u>a. HCl</u>	<u>2.2E-02 lb per MMBtu of heat input</u>	<u>2.5E-02 lb per MMBtu of steam</u>	<u>For M26A, Collect a minimum of 1 dscm</u>

<u>designed to burn solid fuel</u>			<u>output or 0.27 lb per MWh</u>	<u>per run; for M26, collect a minimum of 120 liters per run.</u>
	<u>b. Mercury</u>	<u>5.7E-06 lb per MMBtu of heat input</u>	<u>6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh</u>	<u>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.</u>
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.

<p><u>7. Stokers/sloped grate/others designed to burn wet biomass fuel</u></p>	<p><u>a. CO (or CEMS)</u></p>	<p><u>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)</u></p>	<p><u>1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average</u></p>	<p><u>1 hr minimum sampling time.</u></p>
<p>—</p>	<p><u>b. Filterable PM (or TSM)</u></p>	<p><u>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</u></p>	<p><u>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)</u></p>	<p><u>Collect a minimum of 2 dscm per run.</u></p>
<p>8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</p>	<p>a. CO</p>	<p>460 ppm by volume on a dry basis corrected to 3 percent oxygen</p>	<p>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh</p>	<p>1 hr minimum sampling time.</p>
<p></p>	<p>b. Filterable PM (or TSM)</p>	<p>3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</p>	<p>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)</p>	<p>Collect a minimum of 1 dscm per run.</p>
<p>9. Fluidized bed units designed to burn biomass/bio-based solid</p>	<p>a. CO (or CEMS)</p>	<p>470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,^c 30-day rolling average)</p>	<p>4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average</p>	<p>1 hr minimum sampling time.</p>
<p></p>	<p>b. Filterable PM (or TSM)</p>	<p>1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)</p>	<p>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)</p>	<p>Collect a minimum of 1 dscm per run.</p>
<p>10. Suspension burners designed to burn biomass/bio-based solid</p>	<p>a. CO (or CEMS)</p>	<p>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)</p>	<p>1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average</p>	<p>1 hr minimum sampling time.</p>

	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb	For M26A, collect a minimum of 2 dscm per run; for M26, collect a

			per MWh	minimum of 240 liters per run.
	b. Mercury	2.0E-06 ^a lb per MMBtu of heat input	2.5E-06 ^a lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784, ^b collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 ^a lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 ^a lb per MMBtu of steam output or 1.1E-01 ^a lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb	For M26A, collect a minimum of 2 dscm per run; for M26, collect a

			per MWh	minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

^aIf 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.

^bIncorporated by reference, see §63.14.

^cAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations 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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7195, Jan. 31, 2013, as amended at 80 FR 72821, Nov. 20, 2015]

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Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

IFG-Moyie will comply with the applicable work practice standards listed in this table (items 3-6).

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	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.

2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.
<u>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</u>	<u>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.</u>
<u>4. An existing boiler or process heater located at a major source facility, not including limited use units</u>	<u>Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:</u>
—	<u>a. A visual inspection of the boiler or process heater system.</u>
—	<u>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.</u>
—	<u>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.</u>
—	<u>d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.</u>

	<u>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.</u>
	<u>f. A list of cost-effective energy conservation measures that are within the facility's control.</u>
	<u>g. A list of the energy savings potential of the energy conservation measures identified.</u>
	<u>h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.</u>
<u>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</u>	<p><u>a. You must operate all CMS during startup.</u></p> <p><u>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.</u></p> <p><u>c. You have the option of complying using either of the following work practice standards.</u></p> <p><u>(1) If you choose to comply using definition (1) 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</u></p> <p><u>(2) If you choose to comply using definition (2) 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</u></p>

	<p><u>specified in §63.7505(e).</u> <u>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.</u></p>
<p><u>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</u></p>	<p><u>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.</u> <u>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.</u></p>

^aAs 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).

[78 FR 7198, Jan. 31, 2013, as amended at 80 FR 72823, Nov. 20, 2015]

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Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

The IFG-Moyie Springs Kipper and Sons boiler is subject to the applicable operating limits in this table (items 4.a, 7, and 8)

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 Table 1, 2, 11, 12, or 13 numerical emission limit 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.
<u>4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS IF ESP</u>	<u>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).</u>
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in §63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
<u>7. Performance testing</u>	<u>For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of</u>

	<i>each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.</i>
8. Oxygen analyzer system	<i>For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O₂ 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).</i>
9. SO₂ CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO ₂ CEMS, maintain the 30-day rolling average SO ₂ emission rate at or below the highest hourly average SO ₂ concentration measured during the HCl performance test, as specified in Table 8.

^aA 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]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

IFG-Moyie Springs will conduct performance testing according to the requirement specified in this table.

As stated in §63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

<i>To conduct a performance test for the following pollutant</i>	<i>You must . . .</i>	<i>Using, as appropriate . . .</i>
<i>1. Filterable PM</i>	<i>a. Select sampling ports location and the number of traverse points</i>	<i>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</i>
	<i>b. Determine velocity and volumetric flow-rate of the stack gas</i>	<i>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.</i>
	<i>c. Determine oxygen or carbon dioxide concentration of the stack gas</i>	<i>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</i>
	<i>d. Measure the moisture content of the stack gas</i>	<i>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</i>
	<i>e. Measure the PM emission concentration</i>	<i>Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.</i>

	<u>f. Convert emissions concentration to lb per MMBtu emission rates</u>	<u>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</u>
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. ^a
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
<u>3. Hydrogen chloride</u>	<u>a. Select sampling ports location and the number of traverse points</u>	<u>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</u>
	<u>b. Determine velocity and volumetric flow-rate of the stack gas</u>	<u>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.</u>
	<u>c. Determine oxygen or carbon dioxide concentration of the stack gas</u>	<u>Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.^a</u>
	<u>d. Measure the moisture content of the stack gas</u>	<u>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</u>
	<u>e. Measure the hydrogen chloride emission concentration</u>	<u>Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.</u>
	<u>f. Convert emissions concentration to lb per MMBtu emission rates</u>	<u>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</u>
<u>4. Mercury</u>	<u>a. Select sampling ports location and the number of traverse points</u>	<u>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</u>
	<u>b. Determine velocity and volumetric flow-rate of the stack gas</u>	<u>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.</u>
	<u>c. Determine oxygen or</u>	<u>Method 3A or 3B at 40 CFR part 60, appendix A-</u>

	<u>carbon dioxide concentration of the stack gas</u>	<u>1 of this chapter, or ANSI/ASME PTC 19.10-1981.^a</u>
—	<u>d. Measure the moisture content of the stack gas</u>	<u>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</u>
—	<u>e. Measure the mercury emission concentration</u>	<u>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</u>
—	<u>f. Convert emissions concentration to lb per MMBtu emission rates</u>	<u>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</u>
<u>5. CO</u>	<u>a. Select the sampling ports location and the number of traverse points</u>	<u>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</u>
—	<u>b. Determine oxygen concentration of the stack gas</u>	<u>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</u>
—	<u>c. Measure the moisture content of the stack gas</u>	<u>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</u>
—	<u>d. Measure the CO emission concentration</u>	<u>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.</u>

^aIncorporated 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

At this time, IFG-Moyie Springs intends to show compliance through stack testing and not through fuel analysis. As such, the requirements in this table do not apply.

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 ASTM D6323 ^a (for solid), or ASTM D4177 ^a (for liquid), or ASTM

		D4057 ^a (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples), ASTM D2013/D2013M ^a (for coal), ASTM D5198 ^a (for biomass), or EPA 3050 ^a (for solid fuel), or EPA 821-R-01-013 ^a (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass), or ASTM D5864 ^a for liquids and other solids, or ASTM D240 ^a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173, ^a ASTM E871, ^a or ASTM D5864, ^a or ASTM D240, 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 (for solid samples), or EPA SW-846-7470A ^a (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in §63.7530.
2. HCl	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192, ^a or ASTM D7430, ^a or ASTM D6883, ^a or ASTM D2234/D2234M ^a (for coal) or ASTM D6323 ^a (for coal or biomass), ASTM D4177 ^a (for liquid fuels) or ASTM D4057 ^a (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples), ASTM D2013/D2013M ^a (for coal), or ASTM D5198 ^a (for biomass), or EPA 3050 ^a or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass), ASTM D5864, ASTM D240 ^a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871, ^a or D5864, ^a or ASTM D240, ^a or ASTM D95 ^a (for liquid fuels), or ASTM D4006 ^a (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250, ^a ASTM D6721, ^a ASTM D4208 ^a (for coal), or EPA SW-846-5050 ^a or ASTM E776 ^a (for solid fuel), or EPA SW-846-9056 ^a or SW-846-9076 ^a (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954, ^a ASTM D6350, ^a ISO 6978-1:2003(E), ^a or ISO 6978-2:2003(E), ^a or EPA-1631 ^a or equivalent.

	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 ^a or equivalent.
4. TSM	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192, ^a or ASTM D7430, ^a or ASTM D6883, ^a or ASTM D2234/D2234M ^a (for coal) or ASTM D6323 ^a (for coal or biomass), or ASTM D4177, ^a (for liquid fuels) or ASTM D4057 ^a (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples), ASTM D2013/D2013M ^a (for coal), ASTM D5198 ^a or TAPPI T266 ^a (for biomass), or EPA 3050 ^a or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass), or ASTM D5864 ^a for liquids and other solids, or ASTM D240 ^a or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871, ^a or D5864, 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.

^aIncorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]

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Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits^{ab}

IFG-Moyie Springs will establish operating limits according to the applicable requirements in this table (items 1.c., 4.a., and 5.a.)

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^{ab}

If you have an	And your	You must . . .	Using . . .	According to the
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applicable emission limit for . . .	operating limits are based on . . .			following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	<u>c. Opacity</u>	<u>i. Establish a site-specific maximum opacity level</u>	<u>(1) Data from the opacity monitoring system during the PM performance test</u>	<u>(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests.</u> <u>(b) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run.</u> <u>(c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM</u>

				<u>(or TSM) emission limitation.</u>
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
	c. Alternative Maximum SO ₂ emission rate	i. Establish a site-specific maximum SO ₂ emission rate operating limit according to §63.7530(b)	(1) Data from SO ₂ CEMS and the HCl performance test	(a) You must collect the SO ₂ emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO ₂ emission rate is equal to the highest hourly average SO ₂ emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon	(1) Data from the activated carbon rate monitors and	(a) You must collect activated carbon injection rate data every 15 minutes

		injection rate operating limit according to §63.7530(b)	mercury performance test	during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
<u>4. Carbon monoxide for which compliance is demonstrated by a performance test</u>	<u>a. Oxygen</u>	<u>i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)</u>	<u>(1) Data from the oxygen analyzer system specified in §63.7525(a)</u>	<u>(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.</u> <u>(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.</u> <u>(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.</u>
<u>5. Any pollutant for which compliance is demonstrated by a performance test</u>	<u>a. Boiler or process heater operating load</u>	<u>i. Establish a unit specific limit for maximum operating load according to §63.7520(c)</u>	<u>(1) Data from the operating load monitors or from steam generation monitors</u>	<u>(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.</u> <u>(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.</u> <u>(c) Determine the highest hourly average of the three test run averages</u>

				<u>during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.</u>
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^aOperating limits must be confirmed or reestablished during performance tests.

^bIf 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.

[80 FR 72827, Nov. 20, 2015]

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Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

IFG-Moyie Springs will demonstrate continuous compliance according to the applicable requirements in this table (items 1, 9, and 10).

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	<u>a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and</u>
—	<u>b. Reducing the opacity monitoring data to 6-minute averages; and</u>
—	<u>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.</u>
2. PM CPMS	a. Collecting the PM CPMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate

	at or above the operating limits established during the performance test according to §63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to §63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 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 17, 18, and/or 19 in §63.7530.
<u>9. Oxygen content</u>	<u>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).</u>
—	<u>b. Reducing the data to 30-day rolling averages; and</u>
—	<u>c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.</u>
<u>10. Boiler or process heater operating load</u>	<u>a. Collecting operating load data or steam generation data every 15 minutes.</u>
	<u>b. Reducing the data to 30-day rolling averages; and</u>
—	<u>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).</u>

11. SO ₂ emissions using SO ₂ CEMS	a. Collecting the SO ₂ CEMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO ₂ CEMS emission rate to a level at or below the highest hourly SO ₂ rate measured during the HCI performance test according to §63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015]

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Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

IFG-Moyie Springs will comply with the reporting requirements in this table.

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 . . .
<u>1. Compliance report</u>	<u>a. Information required in §63.7550(c)(1) through (5); and</u>	<u>Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).</u>
—	<u>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</u>	
—	<u>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</u>	
—	<u>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</u>	

<u>contain the information in §63.7550(e)</u>	
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[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 IFG Moyie-Springs will comply with the applicable portions of 40 CFR 63 Subpart A General Provisions.

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
<u>§63.1</u>	<u>Applicability</u>	<u>Yes.</u>
<u>§63.2</u>	<u>Definitions</u>	<u>Yes. Additional terms defined in §63.7575</u>
<u>§63.3</u>	<u>Units and Abbreviations</u>	<u>Yes.</u>
<u>§63.4</u>	<u>Prohibited Activities and Circumvention</u>	<u>Yes.</u>
<u>§63.5</u>	<u>Preconstruction Review and Notification Requirements</u>	<u>Yes.</u>
<u>§63.6(a), (b)(1)-(b)(5), (b)(7), (c)</u>	<u>Compliance with Standards and Maintenance Requirements</u>	<u>Yes.</u>
§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.
<u>§63.6(f)(2) and (3)</u>	<u>Compliance with non-opacity emission standards.</u>	<u>Yes.</u>
<u>§63.6(g)</u>	<u>Use of alternative standards</u>	<u>Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the</u>

		<u>startup work practice (2).</u>
§63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See §63.7500(a).
§63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
<u>§63.6(i)</u>	<u>Extension of compliance</u>	<u>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.</u>
<u>§63.6(j)</u>	<u>Presidential exemption.</u>	<u>Yes.</u>
<u>§63.7(a), (b), (c), and (d)</u>	<u>Performance Testing Requirements</u>	<u>Yes.</u>
§63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c).
<u>§63.7(e)(2)-(e)(9), (f), (g), and (h)</u>	<u>Performance Testing Requirements</u>	<u>Yes.</u>
<u>§63.8(a) and (b)</u>	<u>Applicability and Conduct of Monitoring</u>	<u>Yes.</u>
<u>§63.8(c)(1)</u>	<u>Operation and maintenance of CMS</u>	<u>Yes.</u>
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See §63.7500(a)(3).
<u>§63.8(c)(1)(ii)</u>	<u>Operation and maintenance of CMS</u>	<u>Yes.</u>
§63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
<u>§63.8(c)(2) to (c)(9)</u>	<u>Operation and maintenance of CMS</u>	<u>Yes.</u>
<u>§63.8(d)(1) and (2)</u>	<u>Monitoring Requirements, Quality Control Program</u>	<u>Yes.</u>
<u>§63.8(d)(3)</u>	<u>Written procedures for CMS</u>	<u>Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.</u>
<u>§63.8(e)</u>	<u>Performance evaluation of a CMS</u>	<u>Yes.</u>

<u>§63.8(f)</u>	<u>Use of an alternative monitoring method.</u>	<u>Yes.</u>
<u>§63.8(g)</u>	<u>Reduction of monitoring data</u>	<u>Yes.</u>
<u>§63.9</u>	<u>Notification Requirements</u>	<u>Yes.</u>
<u>§63.10(a), (b)(1)</u>	<u>Recordkeeping and Reporting Requirements</u>	<u>Yes.</u>
<u>§63.10(b)(2)(i)</u>	<u>Recordkeeping of occurrence and duration of startups or shutdowns</u>	<u>Yes.</u>
§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.
<u>§63.10(b)(2)(iii)</u>	<u>Maintenance records</u>	<u>Yes.</u>
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
<u>§63.10(b)(2)(vi)</u>	<u>Recordkeeping for CMS malfunctions</u>	<u>Yes.</u>
<u>§63.10(b)(2)(vii) to (xiv)</u>	<u>Other CMS requirements</u>	<u>Yes.</u>
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
<u>§63.10(c)(1) to (9)</u>	<u>Recordkeeping for sources with CMS</u>	<u>Yes.</u>
§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.
<u>§63.10(c)(12) and (13)</u>	<u>Recordkeeping for sources with CMS</u>	<u>Yes.</u>
§63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
<u>§63.10(d)(1) and (2)</u>	<u>General reporting requirements</u>	<u>Yes.</u>
§63.10(d)(3)	Reporting opacity or visible emission observation results	No.
<u>§63.10(d)(4)</u>	<u>Progress reports under an extension of compliance</u>	<u>Yes.</u>

§63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See §63.7550(c)(11) for malfunction reporting requirements.
<u>§63.10(e)</u>	<u>Additional reporting requirements for sources with CMS</u>	<u>Yes.</u>
<u>§63.10(f)</u>	<u>Waiver of recordkeeping or reporting requirements</u>	<u>Yes.</u>
§63.11	Control Device Requirements	No.
<u>§63.12</u>	<u>State Authority and Delegation</u>	<u>Yes.</u>
<u>§63.13-63.16</u>	<u>Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions</u>	<u>Yes.</u>
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

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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

The IFG-Moyie Springs Kipper and Sons boiler was installed in 1972 and has not been reconstructed; therefore, these alternative emission limits do not apply.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an	a. Mercury	8.0E-07 ^a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample

annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis			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 CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by	1 hr minimum sampling time.

		volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	
	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, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3	1 hr minimum sampling time.

		percent oxygen, 3-run average	
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	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.
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 ^a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03 ^a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable	2.3E-02 lb per MMBtu of	Collect a minimum of 4

	PM (or TSM)	heat input; or (8.6E-04 lb per MMBtu of heat input)	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, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

^aIf 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.

^bIncorporated by reference, see §63.14.

^cAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations 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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72831, Nov. 20, 2015]

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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

The IFG-Moyie Springs Kipper and Sons boiler was installed in 1972 and has not been reconstructed; therefore, these alternative emission limits do not apply.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06 ^a lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu	Collect a minimum of 2 dscm per run.

		of heat input)	
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO b. Filterable PM (or TSM)	460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO b. Filterable PM (or TSM)	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 ^a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	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, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

^aIf 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.

^bIncorporated by reference, see §63.14.

^cAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations 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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72834, Nov. 20, 2015]

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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

The IFG-Moyie Springs Kipper and Sons boiler was installed in 1972 and has not been reconstructed; therefore, these alternative emission limits do not apply.

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.
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-	1 hr minimum sampling time.

		run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable	9.8E-03 lb per MMBtu of heat	Collect a minimum of 3 dscm

	PM (or TSM)	input; or (8.3E-05 ^a lb per MMBtu of heat input)	per run.
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07 ^a lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^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-	1 hr minimum sampling time.

		run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 10-day rolling average)	
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130 ^a ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, ^c 1-day block average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 ^a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^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.

^aIf 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.

^bIncorporated by reference, see §63.14.

^cAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations

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 alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7210, Jan. 31, 2013, as amended at 80 FR 72836, Nov. 20, 2015]

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