NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

Preliminary Findings Regarding the Renewal of a Part 70 Operating Permit

for Indiana Michigan Power Company, dba American Electric Power, Rockport Plant in Spencer County

Part 70 Operating Permit Renewal No.: T147-40656-00020

The Indiana Department of Environmental Management (IDEM) has received an application from Indiana Michigan Power Company, dba American Electric Power, Rockport Plant located at 2791 N US Highway 231, Rockport, Indiana 47635, for a renewal of its Part 70 Operating Permit issued on August 15, 2014. If approved by IDEM’s Office of Air Quality (OAQ), this proposed renewal would allow Indiana Michigan Power Company, dba American Electric Power, Rockport Plant to continue to operate its existing source.

This draft permit does not contain any new equipment that would emit air pollutants; however, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g., changes that add or modify synthetic minor emission limits). This notice fulfills the public notice procedures to which those conditions are subject. IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow for these changes.

A copy of the permit application and IDEM's preliminary findings are available at:

Spencer County Public Library
210 Walnut Street
Rockport, IN 47635

A copy of the preliminary findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

A copy of the preliminary findings is also available via IDEM's Virtual File Cabinet (VFC.) Please go to: http://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

How can you participate in this process?

The date that this notice is posted on IDEM’s website (https://www.in.gov/idem/5474.htm) marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the air pollution impact of this draft permit are received, with a request for a public hearing, IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.
Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM’s mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number T147-40656-00020 in all correspondence.

Comments should be sent to:

Mena Mekhail  
IDEM, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251  
(800) 451-6027, ask for Mena Mekhail or (317) 234-7434  
Or dial directly: (317) 234-7434  
Fax: (317) 232-6749 attn: Mena Mekhail  
E-mail: mmekhail@idem.in.gov

All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor, or noise. For such issues, please contact your local officials.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens’ Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM’s response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM’s decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, and the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251.

If you have any questions, please contact Mena Mekhail of my staff at the above address.

Josiah K. Balogun, Section Chief  
Permits Branch  
Office of Air Quality
Indiana Michigan Power Company, dba American Electric Power -
Rockport Plant
2791 N. U.S. Highway 321
Rockport, Indiana 47635

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

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Attachment F: Clean Air Interstate Rule (CAIR)

Attachment G: Federal Consent Decree

Attachment H: New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines [40 CFR 60, Subpart IIII]
SECTION A  SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

| Source Address:                      | 2791 N. U.S. Highway 321, Rockport, Indiana 47635 |
| General Source Phone Number:         | 812 649 9171                                      |
| SIC Code:                            | 4911 (Electric Services)                         |
| County Location:                     | Spencer                                          |
| Source Location Status:              | Attainment for all criteria pollutants           |
| Source Status:                       | Part 70 Operating Permit Program                  |
|                                      | Major Source, under PSD Rules                    |
|                                      | Major Source, Section 112 of the Clean Air Act    |
|                                      | 1 of 28 Source Categories                        |

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[This is an affected unit under 40 CFR 63, Subpart UUUU]
[This is an affected unit under 40 CFR 60, Subpart D]

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for
NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

- This is an affected unit under 40 CFR 63, Subpart UUUUU
- This is an affected unit under 40 CFR 60, Subpart D

(c) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

- These are affected units under 40 CFR 60, Subpart D
- These are affected units under 40 CFR 63, Subpart DDDDD

(d) A coal storage and handling system for MB1 and MB2, with installation started in 1981 and completed in 1984, consisting of the following equipment:

1. Two (2) barge unloading stations, identified as Stations 1 and 2, each with a baghouse, or a dust extraction system using water injection, and foam or water spray for particulate control, each with a bucket elevator with foam or water spray and partial enclosure for particulate control, and Conveyors 1 and 2 with water spray for particulate control.

2. Enclosed conveyor systems, including fully and partially enclosed conveyors, with foam, water, or other equivalent dust suppression measures for particulate control, with the transfer points enclosed by buildings with baghouses, or a dust extraction system using water injection, for particulate control at Stations 5, 6 and 7. A stacker reclaim system is used to drop coal to the storage pile(s). The coal handling system has a design throughput capacity of 4000 tons per hour up to the stacker-reclaimers, and 1600 tons per hour from Station 7E and 7W to the coal bunkers in the units.

3. Coal storage pile(s), with fugitive dust emissions controlled by watering.

4. Coal crushing Station 8, with a maximum throughput of 2618 tons per hour for the east system and 2542 tons per hour for the west system, with a baghouse for particulate control, or a dust extraction system using water injection.

5. Blending and transfer Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

6. Blending and transfer Station 10.

7. Two (2) storage silos for Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.
(8) Coal sampling and transfer Stations A and D, each with a baghouse for particulate control, or a dust extraction system using water injection.

(9) Bunkering conveyors AB, BC, CB, DC, and FD, each fully enclosed, each with a baghouse for particulate control, or a dust extraction system using water injection.

(10) Fourteen (14) storage silos for Unit 1, with particulate control as follows:

(A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 1, or

(B) one or more dust extraction systems using water injection.

(11) Fourteen (14) storage silos for Unit 2, with particulate control as follows:

(A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 2, or

(B) one or more dust extraction systems using water injection.

[These are affected units under 40 CFR 60, Subpart Y]

(e) Dry fly ash handling:

(1) Fly ash handling for MB1, installed in approximately 1982, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by a bin vent filter on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.

(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.

(2) Fly ash handling for MB2, with installation completed in 1986, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by two (2) bin vent filters on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.
(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.

(3) One (1) fly ash barge loading facility, with pneumatic unloading system from covered truck to covered barge with a maximum throughput rate of 52.5 tons ash per hour, with a baghouse on a river cell for particulate control.

(4) Rail loading equipment associated with the former fly ash temporary storage facility, with a maximum throughput rate of 52.5 tons ash per hour. The loader has a baghouse for dust control.

PAC Handling and Storage Operations

(f) Four (4) pneumatic truck unloading stations, two (2) at each set of silos, for transferring halogenated and non-halogenated activated carbon from transports to storage silos, permitted in 2008, 2010, and 2013 with particulate emissions controlled by a bin vent filter.

(g) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2008, 2010, and 2013 with particulate emissions from each silo controlled by a bin vent filter.

(h) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(i) Four (4) metering pressure tanks per silo, with a maximum system capacity of injecting 4000 pounds per hour of halogenated or non-halogenated activated carbon into the exhaust ductwork, permitted in 2008, 2010, and 2013 with particulate emissions from the pressure tanks controlled via the silo bin vent filter.

DSI Handling and Storage operation

(j) Two (2) pneumatic truck unloading systems (one system per unit) for transferring sodium bicarbonate from up to two transport trucks simultaneously to the attached storage silos, permitted in 2013, with particulate emissions controlled by a bin vent filter on the silo receiving the sorbent being unloaded.

(k) Four (4) silos, two (2) per unit, for storing sodium bicarbonate, each with a maximum storage capacity of 1440 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(l) Injection metering system that includes three (3) metering feeders directly fed from each storage silo, blowers, and piping necessary to inject up to 10 tons per hour of sodium bicarbonate into the ductwork feeding the four electrostatic precipitators on each unit, permitted in 2013, with particulate emissions controlled by a bin vent filter.
A.3 Specifically Regulated Insignificant Activities

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Space heaters using the following fuels: Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than three-tenths (0.3) percent sulfur by weight, including space heaters WHU-1 and WHU-2, each with 1.1 MMBtu/hr heat input capacity.

Emergency generators as follows: Diesel generators not exceeding 1600 horsepower.

(b) Degreasing operations that do not exceed 145 gallons per 12 months.

(c) Cleaners and solvents characterized as follows:

(1) Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;

(2) Having a vapor pressure equal to or less than 0.7 kPa; 5mm Hg; or 0.1 psi measured at 20°C (68°F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(d) Coal bunker and coal scale exhausts and associated dust collector vents.

[This is an affected unit under 40 CFR 60, Subpart Y]

(e) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO₂ 5 pounds per hour or 25 pounds per day, NOₓ 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

Ponded bottom ash handling and management, including dredging bottom ash ponds and loading material into trucks.

(f) Wet process bottom ash handling, with hydroveyors conveying ash to storage ponds, with water level sufficient to prevent ash re-entrainment.

(g) Emergency generators as follows: Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, constructed in 1983/1984, each with 25.16 MMBtu/hr heat input capacity.

[These are affected units under 40 CFR 63, Subpart ZZZZ]

(h) Five (5) No. 2 fuel oil-fired space heaters designated as WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9, with heat input capacities of 4.5 MMBtu/hr, 3.0 MMBtu/hr, 2.75 MMBtu/hr, 3.5 MMBtu/hr, and 4.5 MMBtu/hr, respectively.

(i) One (1) No. 2 fuel oil-fired space heater, identified as WHU-10, approved in 2018 for construction, with heat input capacity of 2.4 MMBtu/hr.

(j) Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.

[These are affected units under 40 CFR 60, Subpart IIII]
A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);
SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]
Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]
(a) This permit, T147-40656-00020, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]
Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7][IC 13-17-12]
Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]
The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]
This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]
(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U.S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.
B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source’s compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and
(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)] [326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee’s control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The
PMPs and their submittals do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

1. An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;
2. The permitted facility was at the time being properly operated;
3. During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
4. For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;
   
   Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
   Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
   Facsimile Number: 317-233-6865

5. For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

   Indiana Department of Environmental Management
   Compliance and Enforcement Branch, Office of Air Quality
   100 North Senate Avenue
   MC 61-53 IGCN 1003
   Indianapolis, Indiana 46204-2251

   within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;
(B) Any steps taken to mitigate the emissions; and
(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.
(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

1. The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

2. The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

3. The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

4. The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T147-40656-00020 and issued pursuant to permitting programs approved into the state implementation plan have been either:

1. incorporated as originally stated,

2. revised under 326 IAC 2-7-10.5, or

3. deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

B.14 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

The Permittee’s right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source’s existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification,
revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source’s failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if,
subsequent to the completeness determination, the Permittee fails to submit by the
deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any
additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

(a) Permit amendments and modifications are governed by the requirements of
326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify
this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating
permit amendments and permit modifications for purposes of the acid rain portion of a
Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean
Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be
submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of
326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) The Permittee may implement administrative amendment changes addressed in the
request for an administrative amendment immediately upon submittal of the request.
[326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs
[326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic
incentives, marketable Part 70 permits, emissions trading, and other similar programs or
processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit
modification procedures may be used for Part 70 modifications involving the use of
economic incentives, marketable Part 70 permits, emissions trading, and other similar
approaches to the extent that such minor Part 70 permit modification procedures are
explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable
requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in
326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions
is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air
Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in
this permit (whether expressed herein as a rate of emissions or in terms of total
emissions);
(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.
(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of SO₂ or NOₓ under 326 IAC 21 or 326 IAC 10-4.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]
A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]
Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee’s right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]
(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.
SECTION C  SOURCE OPERATION CONDITIONS

Emission Limitations and Standards  [326 IAC 2-7-5(1)]

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Opacity  [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.3 Open Burning  [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.4 Incineration  [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.5 Fugitive Dust Emissions  [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.6 Stack Height  [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using ambient air quality modeling pursuant to 326 IAC 1-7-4. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.7 Asbestos Abatement Projects  [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least
thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

   (A) Asbestos removal or demolition start date;

   (B) Removal or demolition contractor; or

   (C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(3).

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to
Testing Requirements [326 IAC 2-7-6(1)]

C.8 Performance Testing [326 IAC 3-6]

<table>
<thead>
<tr>
<th>(a)</th>
<th>For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:</th>
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<tbody>
<tr>
<td></td>
<td>Indiana Department of Environmental Management</td>
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<tr>
<td></td>
<td>Compliance and Enforcement Branch, Office of Air Quality</td>
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<td>100 North Senate Avenue</td>
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<td>MC 61-53 IGCN 1003</td>
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<td></td>
<td>Indianapolis, Indiana 46204-2251</td>
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</table>

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

| (b) | The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). |

| (c) | Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period. |

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

<table>
<thead>
<tr>
<th>(a)</th>
<th>For new units:</th>
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<tbody>
<tr>
<td></td>
<td>Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>(b)</th>
<th>For existing units:</th>
</tr>
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<tr>
<td></td>
<td>Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance to begin such monitoring. If, due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:</td>
</tr>
</tbody>
</table>
in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(d) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

C.11 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]

C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]
C.13 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.14 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5][326 IAC 2-7-6]

(I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to normal or usual manner of operation.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records; and/or

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall record the reasonable response steps taken.

(II) CAM Response to excursions or exceedances.

(a) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal.
without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) CAM recordkeeping requirements.
(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6][326 IAC 2-2][326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.
(BB) The dates analyses were performed.
(CC) The company or entity that performed the analyses.
(DD) The analytical techniques or methods used.
(EE) The results of such analyses.
(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.
(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.
(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:
(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3] [40 CFR 64] [326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.
(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C - General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

Stratospheric Ozone Protection

C.19 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.
DRAFT

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

<table>
<thead>
<tr>
<th><strong>Emissions Unit Description [326 IAC 2-7-5(14)]</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><em>(a)</em> One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.</td>
</tr>
<tr>
<td><strong>This is an affected unit under 40 CFR 63, Subpart UUUUU</strong></td>
</tr>
<tr>
<td><strong>This is an affected unit under 40 CFR 60, Subpart D</strong></td>
</tr>
</tbody>
</table>

| *(b)* One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010, and 2013 with particulate emissions controlled by a bin vent filter. |
| **This is an affected unit under 40 CFR 63, Subpart UUUUU** |
| **This is an affected unit under 40 CFR 60, Subpart D** |

PAC Handling and Storage Operations

*(f)* Four (4) pneumatic truck unloading stations, two (2) at each set of silos, for transferring halogenated and non-halogenated activated carbon from transports to storage silos, permitted in 2008, 2010, and 2013 with particulate emissions controlled by a bin vent filter.
(g) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2008, 2010, and 2013 with particulate emissions from each silo controlled by a bin vent filter.

(h) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(i) Four (4) metering pressure tanks per silo, with a maximum system capacity of injecting 4000 pounds per hour of halogenated or non-halogenated activated carbon into the exhaust ductwork, permitted in 2008, 2010, and 2013 with particulate emissions from the pressure tanks controlled via the silo bin vent filter.

DSI Handling and Storage operation

(j) Two (2) pneumatic truck unloading systems (one system per unit) for transferring sodium bicarbonate from up to two transport trucks simultaneously to the attached storage silos, permitted in 2013, with particulate emissions controlled by a bin vent filter on the silo receiving the sorbent being unloaded.

(k) Four (4) silos, two (2) per unit, for storing sodium bicarbonate, each with a maximum storage capacity of 1440 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(l) Injection metering system that includes three (3) metering feeders directly fed from each storage silo, blowers, and piping necessary to inject up to 10 tons per hour of sodium bicarbonate into the ductwork feeding the four electrostatic precipitators on each unit, permitted in 2013, with particulate emissions controlled by a bin vent filter.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1 Pollution Control Project (PCP) [326 IAC 2-2-1(x)(2)(H)]

Pursuant to Source Modification 147-17468-00020, issued November 13, 2003, and 326 IAC 2-2-1(x)(2)(H) as it existed on November 13, 2003:

The replacement of the LNB and the installation of an OFA system for each of the boilers MB1 and MB2 to reduce NOX emissions are considered to be a pollution control project; therefore, the project's CO collateral emissions are excluded from the 326 IAC 2-2 PSD requirements.

D.1.2 Prevention of Significant Deterioration (PSD) - Best Available Control Technology for PM and SO₂ [326 IAC 2-2]

Pursuant to Approval to Construct EPA-5-78-A-1, issued October 27, 1977, 40 CFR 52.21 (Federal Regulations for the Prevention of Significant Deterioration of Air Quality) and 326 IAC 2-2, PSD rules the Permittee shall comply with the following:

(a) Particulate Matter (PM) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 0.1 pound per million British thermal unit (MMBtu) heat input.

(b) Sulfur dioxide (SO₂) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 1.2 pound per MMBtu heat input.

(c) The Permittee may not alter the height of the boilerhouse as presented in the
construction application. The dispersion modeling in the application relies upon a stack height expressed as 2.5 times the height of the boilerhouse. Any change in the boilerhouse height would alter the dispersion of sulfur dioxide and particulates.

(d) The Permittee may not alter the design stack parameters identified in the construction application including, but not limited to, exit gas temperature, exit gas velocity and stack diameter (inside top). The air quality analysis relies heavily on the combination of stack parameters, control devices, the emission limitations and any change in those factors could change the results of the air quality analysis. Therefore, design changes in Units 1 and 2 must receive the prior written authorization of IDEM, OAQ.

Compliance with this condition shall satisfy the requirements of 40 CFR 52.21, 326 IAC 2-2, PSD rules.

Compliance with condition D.1.2(a) shall satisfy the PM limit under 326 IAC 6-2-1(g) - Particulate Emission Limitations for Sources of Indirect Heating.

Compliance with condition D.1.2(b) shall satisfy the requirements of 326 IAC 7-1.1-2 - Sulfur dioxide emission limitations.

D.1.3 PM, PM10 and PM2.5 PSD Netting Credit [326 IAC 2-2]

(a) Pursuant to SSM 147-32890-00020, issued on September 19, 2013, the following units shall be limited to render the requirements of PSD not applicable:

**Boiler MB1 and Boiler MB2**

1. The total PM emissions from Boiler MB1 and Boiler MB2 shall be limited to 2575 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

2. The total PM10 emissions from Boiler MB1 and Boiler MB2 shall be limited to 1725 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

3. The total PM2.5 emissions from Boiler MB1 and Boiler MB2 shall be limited to 746 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

**Dry Sorbent Injection System Serving Units MB1 and MB21**

1. The Dry Sorbent delivered to the site shall be limited to 142,500 tons per twelve (12) consecutive month period for both units with compliance determined at the end of each month.

2. The PM emissions from the Sorbent Silos shall be limited to 0.73 lbs per thousand tons of dry sorbent.

3. The PM10 emissions from the Sorbent Silos shall be limited to 0.48 lbs per thousand tons of dry sorbent.

4. The PM2.5 emissions from the Sorbent Silos shall be limited to 0.0028 lbs per thousand tons of dry sorbent.

5. The PM emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 33.54 lbs per thousand tons of dry sorbent.
(6) The PM10 emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 6.46 lbs per thousand tons of dry sorbent.

(7) The PM2.5 emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 1.54 lbs per thousand tons of dry sorbent.

**Activated Carbon Injection System Serving Units MB1 and MB21**

(1) The Activated Carbon delivered to the site shall be limited to 35,040 tons per twelve (12) consecutive month period for both units with compliance determined at the end of each month.

(2) The PM emissions from the Activated Carbon Silo bin vent filter shall be limited to 56.68 lbs per thousand tons of Activated Carbon.

(3) The PM10 emissions from the Activated Carbon Silo bin vent filter shall be limited to 36.99 lbs per thousand tons of Activated Carbon.

(4) The PM2.5 emissions from the Activated Carbon Silo bin vent filter shall be limited to 5.99 lbs per thousand tons of Activated Carbon.

(5) The PM emissions from the paved roads used for the Activated Carbon delivery shall be limited to 20.55 lbs per thousand tons of Activated carbon delivered.

(6) The PM10 emissions from the paved roads used for the Activated Carbon delivery shall be limited to 4.00 lbs per thousand tons of Activated carbon delivered.

(7) The PM2.5 emissions from the paved roads used for the Activated Carbon delivery shall be limited to 1.14 lbs per thousand tons of Activated carbon delivered.

**Ash Handling to Silos**

(1) The PM emissions from the Ash Silos shall be limited to 0.2 lbs per thousand tons of dry ash.

(2) The PM10 emissions from the Ash Silos shall be limited to 0.2 lbs per thousand tons of dry ash.

(3) The PM2.5 emissions from the Ash Silos shall be limited to 0.1 lbs per thousand tons of dry ash.

(4) The total amount of dry ash loaded shall be limited to 583,743 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

**Ash Hauling on Paved Roads**

(1) The PM emissions from the paved roads used for the Ash Hauling shall be limited to 81.59 lbs per thousand tons of conditioned ash.

(2) The PM10 emissions from the paved roads used for the Ash Hauling shall be limited to 15.57 lbs per thousand tons of conditioned ash.
(3) The PM2.5 emissions from the paved roads used for the Ash Hauling shall be limited to 3.90 lbs per thousand tons of conditioned ash.

(4) The total amount of conditioned ash loaded and dumped shall be limited to 686,846 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Ash Hauling on Unpaved Roads

(1) The PM emissions from the unpaved roads used for the Ash Hauling shall be limited to 72.83 lbs per thousand tons of conditioned ash.

(2) The PM10 emissions from the unpaved roads used for the Ash Hauling shall be limited to 19.33 lbs per thousand tons of conditioned ash.

(3) The PM2.5 emissions from the unpaved roads used for the Ash Hauling shall be limited to 1.92 lbs per thousand tons of conditioned ash.

(4) The total amount of conditioned ash loaded and dumped shall be limited to 686,846 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Loading and Dumping of conditioned Ash

(1) The PM emissions from the loading and dumping of the conditioned ash shall be limited to 0.22 lbs per thousand tons of conditioned ash.

(2) The PM10 emissions from the loading and dumping of the conditioned ash shall be limited to 0.1 lbs per thousand tons of conditioned ash.

(3) The PM2.5 emissions from the loading and dumping of the conditioned ash shall be limited to 0.01 lbs per thousand tons of conditioned ash.

(4) The total amount of conditioned ash loaded and dumped shall be limited to 686,846 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Landfill Emissions:

(1) The PM emissions from the landfill operation for the conditioned ash shall be limited to 183.59 lbs per thousand tons of conditioned ash.

(2) The PM10 emissions from the landfill operation for the conditioned ash shall be limited to 55.45 lbs per thousand tons of conditioned ash.

(3) The PM2.5 emissions from the landfill operation for the conditioned ash shall be limited to 6.92 lbs per thousand tons of conditioned ash.

(4) The total amount of conditioned ash loaded and dumped shall be limited to 686,846 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) In order to render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2013 project to install DSI and ACI for CO₂, the Permittee shall comply with the following:
(1) The total amount of sorbent used on MB1 and MB2 at Rockport Plant shall not exceed 142,500 tons in a 12 month period.

(2) Compliance with the sorbent tonnage limit in (1) shall be determined by the use of inventory and delivery records.

Compliance with these emission limits will ensure that the net emissions increase from this modification is less than twenty-five (25) tons of PM per year, less than fifteen (15) tons of PM10 per year and less than ten (10) tons of PM2.5 per year and therefore will render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2013 project to install DSI and ACI.

Compliance with these requirements will ensure that the potential to emit from this modification is less than seventy five thousand (75,000) tons of CO2 and therefore will render the requirements of 326 IAC 2-2 not applicable to the 2013 project to install DSI and ACI.

D.1.4 Opacity Limitations [326 IAC 5-1]

(a) Pursuant to 326 IAC 5-1-2 (Opacity Limitations), the following applies:

Except as provided in Condition D.1.4(b), opacity from boilers MB1 and MB2 shall meet the following during time periods exempted from the opacity limit of 40 CFR 60 Subpart D, unless otherwise stated in this permit:

(1) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(2) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

(b) Temporary Alternative Opacity Limit (TAOL) [326 IAC 5-1-8]

In the event that Permittee is unable to meet the limitations in D.1.4(a), the Permittee shall comply with the following site specific TAOL:

(1) When building a new fire in a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed a total of two (2) hours (twenty (20) six (6)-minute averaging periods) during the startup period, or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitator, whichever occurs first.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 once the flue gas temperature has dropped below two hundred fifty (250) degrees Fahrenheit at the inlet of the electrostatic precipitators for a period not to exceed a total of one and half (1.5) hour (fifteen (15) six (6)-minute averaging periods) during the shutdown period.

D.1.5 Consent Decree (Federal District Court for the Southern District of Ohio on February 22, 2013, as modified via Fifth Joint Modification of Consent Decree) Boiler MB1 and MB2 SO2 emission limits:

(a) “Continuously Operate” or “Continuous Operation” means that when an SCR, FGD, DSI, Enhanced DSI, ESP or other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.
(b) "Dry Sorbent Injection" or "DSI" means a pollution control system in which sorbent is injected into the flue gas path prior to the particulate pollution control devices for the purpose of reducing SO2 emissions. For the purposes of DSI systems required to be installed at the Rockport Units only, the DSI systems shall utilize a sodium based sorbent and be designed to inject at least 10 tons per hour of a sodium based sorbent. Defendants may utilize a different sorbent at the Rockport Units provided they obtain prior approval from Plaintiffs pursuant to Paragraph 148 of the Consent Decree.

(c) "Enhanced Dry Sorbent Injection" or "Enhanced DSI" means a pollution control system in which a dry sorbent is injected into the flue gas prior to the NOx and particulate matter controls in order to provide additional mixing and improved SO2 removal as compared to Dry Sorbent Injection.

(d) A "30-Day Rolling Average Emission Rate" for Rockport means, and shall be expressed as, lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the combined Rockport stack during a Day which is an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; second, sum the total heat input to both Rockport Units in mmBTU during the Day which was an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Days which were Operating Days for either or both Rockport Units by the total heat input during the thirty such Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Day which is an Operating Day for either or both Rockport Units. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

(1) Emissions and BTU inputs from both Rockport Units that occur during a period of Malfunction at either Rockport Unit shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

(2) Emissions of NOx and BTU inputs from both Rockport Units that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a single Rockport Unit during any 30-Day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR at the Unit in question in accordance with manufacturers’ specifications and good engineering practices. A “Cold Start Up Period” occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NOx emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) at a single unit shall be the lesser of (i) those NOx emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NOx emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

(3) For SO2, shall include all emissions and BTUs commencing from the time a single Rockport Unit is synchronized with a utility electric distribution system through the time that both Rockport Units cease to combust fossil fuel and the fire is out in both boilers.
(e) "Plant-Wide Annual Tonnage Limitation for SO2 at Rockport" means the sum of tons of SO2 emitted during all periods of operation from the Rockport Plant, including, without limitations, all SO2 emitted during periods of startup, shutdown, and Malfunction, during relevant calendar year (i.e., January 1-December 31).

(f) The source shall install the DSI systems on Unit 1 and Unit 2 no later than April 16, 2015. Rockport Unit 2 must install Enhanced DSI by June 1, 2020 and Rockport Unit 1 must install Enhanced DSI by December 31, 2020.

(g) Beginning January 1, 2018 and ending on December 31, 2019 Rockport Plant will be limited to emitting 26,000 tons per year of SO2 from Boilers MB1 and MB2;

(h) Beginning January 1, 2020 and ending on December 31, 2020 Rockport Plant will be limited to emitting 22,000 tons per year of SO2 from Boilers MB1 and MB2;

(i) Beginning January 1, 2021 and ending on December 31, 2028 Rockport Plant will be limited to emitting 10,000 tons per year of SO2 from Boilers MB1 and MB2.

(j) Notwithstanding the existence of any other compliance options in Paragraphs 87 and 133 of the Consent Decree, AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028.

(1) On or before March 31, 2025, AEP Defendants shall submit to PJM Interconnection, LLC, or any other regional transmission organization with jurisdiction over the Rockport Units, notification of the planned retirement of Rockport Unit 1 by no later than December 31, 2028, and a request for such regional transmission organization to evaluate and identify any reliability concerns associated with such retirement.

(k) Beginning January 1, 2029, Rockport Plant will be limited to emitting no more than 5000 tons of SO2 per year from Boiler MB2.

(l) In addition to the Plant-Wide Annual Tonnage Limitation for SO2 at Rockport, beginning on the thirtieth Day which is an Operating Day for either or both Rockport Units in calendar year 2021, SO2 emissions from the Rockport Units shall be limited to 0.15 lb/mmBTU on a 30-Day Rolling Average Basis at the Rockport combined stack (30-Day Rolling Average Emission Rate for SO2 at Rockport). The 30-day rolling average emission rate for Rockport shall be calculated in accordance with Condition D.1.5(d) and deviations shall be reported to IDEM quarterly and to the other parties to the Consent Decree in accordance with the provisions of the Consent Decree. Nothing in the Consent Decree shall be construed to prohibit the AEP Defendants from further optimizing the Enhanced DSI system, utilizing alternative sorbents, or upgrading the SO2 removal technology at the Rockport Units so long as the Units maintain compliance with the 30-day Rolling Average Emission Rate for SO2 at Rockport and the 30-day Rolling Average Emission Rate for NOx at Rockport.

(m) Beginning on March 31, 2017, and continuing annually thereafter, the source shall report:

(1) The actual tons of SO2 emitted from Units 1 and 2 at the Rockport plant for the prior calendar year.

(2) The Plant-Wide Annual Tonnage Limitation for SO2 at the Rockport plant for the prior year as set forth in Paragraph 89A of the consent Decree;
For the annual reports for calendar years 2015 through 2020, Defendants shall report the daily sorbent deliveries to the Rockport Plant by weight. Beginning in calendar year 2021, the annual reports shall report the 30-day rolling average SO₂ Emissions Rate at the Rockport stack as described in Condition D.1.5(d). Reporting of daily sorbent deliveries will no longer be required beginning with calendar year 2021.

AEP Defendants shall provide to the Plaintiffs and IDEM a copy of the notification submitted to PJM Interconnection, LLC, or any other regional transmission organization pursuant to Paragraph 140.a of the Consent Decree and Condition D.1.5(j)(1), and a copy of any response received from PJM Interconnection, LLC, or any other the regional transmission organization.

No later than December 31, 2017 for Unit 1 and June 1, 2020 for Unit 2 SCR shall be continuously operated, as defined in Condition D.1.5(a). (Section B, Paragraph 68 of the Consent Decree as modified).

Beginning on the thirtieth Day which is an Operating Day for either one or both Rockport Units in calendar year 2021, average NOₓ emissions from the Rockport Units shall be limited to 0.090 lb/mmBTU on a 30-day Rolling Average Basis at the combined stack for the Rockport Units. Emissions shall be calculated in accordance with the provisions of Condition D.1.5(d) and reported in accordance with the requirements of Paragraph J in Appendix B of the Consent Decree.

D.1.6 Hourly SO₂ Emission Limitations [326 IAC 2-2]

In accordance with the modeling analysis required for Approval to Construct EPA-5-78-A-1, issued October 27, 1977, and 40 CFR 52.21, the combined SO₂ emission rate for Boilers MB1 and MB2 shall not exceed 28,663 pounds of SO₂ per hour.

D.1.7 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the PAC handling and storage operations shall not exceed the emission limits specified in the table below:

<table>
<thead>
<tr>
<th>Unit Description</th>
<th>Max. Process Weight Rate (tons/hr)</th>
<th>Allowable Particulate Emission Rate (lbs/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PAC Handling and Storage Operations</td>
<td>30</td>
<td>40</td>
</tr>
</tbody>
</table>

The allowable particulate emission rates were calculated using the equation below:

\[ E = 4.10 \times P^{0.67} \]

Where:

- \( E \) = rate of emission in pounds per hour
- \( P \) = process weight rate in tons per hour

Pursuant to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the DSI handling and storage operations shall not exceed the emission limits specified in the table below:
<table>
<thead>
<tr>
<th>Unit Description</th>
<th>Max. Process Weight Rate (tons/hr)</th>
<th>Allowable Particulate Emission Rate (lbs/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSI Handling and Storage</td>
<td>50</td>
<td>44.60</td>
</tr>
</tbody>
</table>

The allowable particulate emission rates were calculated using the equation below:
Interpolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

\[ E = 55.0 P^{0.11} - 40 \]

Where:
- \( E \) = rate of emission in pounds per hour and
- \( P \) = process weight rate in tons per hour

**Compliance Determination Requirements [326 IAC 2-7-5(1)]**

**D.1.8 Particulate Control [326 IAC 2-7-6(6)]**

In order to comply with Condition D.1.7, the bin vent filters for particulate control shall be in operation and control emissions at all times the respective unloading stations, silos and pressure tanks are in operation.

**D.1.9 Compliance Determination Equation**

In order to comply with Condition D.1.3 – PSD Minor Limits, the PM, PM10 and PM2.5 emissions shall be determined from the following equations:

The monthly PM emissions shall be calculated using the following formula:

\[ E = (HIC_{S012} \times EF_{PMCS012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:
- \( HIC_{S012} \) = Monthly Heat Input (MMBtu/month)
- \( EF_{PMCS012} \) = a value of 0.0365 lb/MMBtu of PM for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

The monthly PM10 emissions shall be calculated using the following formula:

\[ E = (HIC_{S012} \times EF_{PM10CS012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:
- \( HIC_{S012} \) = Monthly Heat Input (MMBtu/month)
- \( EF_{PM10CS012} \) = a value of 0.0245 lb/MMBtu of PM10 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

The monthly PM2.5 emissions shall be calculated using the following formula:

\[ E = (HIC_{S012} \times EF_{PM25CS012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:
- \( HIC_{S012} \) = Monthly Heat Input (MMBtu/month)
EFPM10CS012 = a value of 0.011 lb/MMBtu of PM2.5 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

D.1.10 Testing Requirements [326 IAC 2-7-6(1), (6)][326 IAC 2-1.1-11]

In order to demonstrate the compliance status with Condition D.1.2 and D.1.3, the Permittee shall perform PM stack testing of the emissions from the common stack using methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following the most recent valid compliance demonstration. Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

D.1.11 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule, or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the boiler vented to the ESP is in operation.

(b) Operation of the electrostatic precipitator is not required during startup and shutdown periods.

D.1.12 Operation of Low NOX Burners and Overfire Air Systems [326 IAC 2-7-6(6)]

Pursuant to SSM 147-17468-00020, issued November 13, 2003, except as otherwise provided by statute or rule, or in this permit, the low NOX burners and overfire air system for each boiler, MB1 and MB2, shall be operated at all times that the respective boiler is firing coal.

D.1.13 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COMS shall be in operation at all times that a draft fan is in operation.

(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.
D.1.14 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 12][40 CFR 60, Subpart D] [326 IAC 7-2][40 CFR 52.21]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), 326 IAC 12, 40 CFR 60.45, Approval to Construct EPA-5-78-A-1, issued October 27, 1977, and 40 CFR 52.21, continuous emission monitoring systems for Units MB1 and MB2 shall be calibrated, maintained, and operated for measuring opacity, SO2, NOX, and either CO2 or O2, which meet the performance specifications of 326 IAC 3-5-2 and 40 CFR 60.45.

(b) Pursuant to 40 CFR 60.13(e), except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of 40 CFR 60.13, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of 40 CFR 60.13 for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of 40 CFR 60.13 for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(c) Pursuant to 40 CFR 60.45(g)(2)(i), Approval to Construct EPA-5-78-A-1, and 40 CFR 52.21, excess SO2 emissions for affected facilities are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

(d) Excess NOx emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44. [40 CFR 60.45(g)(3)]

(e) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

(f) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(g) Whenever a NOx CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the SCR catalyst bed inlet temperature with a continuous temperature monitoring system no less often than once per four (4) hours. Except during periods of Unit non-operation Unit start-up and Unit shutdown activities, and prior to the required operation of an SCR on either unit in accordance with Condition D.1.5(o), should the catalyst bed inlet temperature fall below 500°F, the minimum temperature for SCR operation, the Permittee shall take a reasonable response action. Section C – Response to Excursions or Exceedances contains the Permittee’s obligation with regard to the reasonable response steps required by this condition. A temperature reading that is
below the minimum temperature is not a deviation from this permit. Failure to take reasonable response steps shall be considered a deviation from this permit.

(h) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, 40 CFR 60, or 40 CFR 75.

D.1.15 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-5][326 IAC 7-2][326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the SO2 limits in Condition D.1.2. Compliance with these limits shall be determined using SO2 CEMS data, and demonstrated using a thirty (30) day rolling weighted average.

Compliance Assurance Monitoring Requirements [40 CFR 64]

D.1.16 Transformer-Rectifier (T-R) Sets [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be continuously monitored when the units are in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) A response shall be taken in accordance with Section C – Response to Excursions or Exceedances (Condition C.14(II)) whenever the number of T-R sets out of service is above thirty-two (32) per unit. T-R set failure resulting in more than thirty-two (32) per unit out of service is not a deviation from this permit. Failure to take a reasonable response in accordance with Condition C.14(II) when more than thirty-two (32) T-R Sets are out of service shall be considered a deviation from this permit. Failure to use reasonable procedures in a response to an excursion or exceedance of the indicator range set forth above in accordance with Condition C.14(II)(a)(2) may result in the requirement to develop a Quality Improvement Plan as set forth in Condition C.14(II)(c).

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.1.17 SO2 Monitoring System Downtime [326 IAC 2-7-6][326 IAC 2-7-5(3)]

Whenever the SO2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments, the following shall be used to provide information related to SO2 emissions:

(a) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(b) If the CEMS is down for twenty-four (24) hours or more, fuel sampling shall be conducted as follows:

1. Solid fuel sampling shall be conducted as specified in 326 IAC 3-7-2(b). Fuel sample preparation and analysis shall be conducted as specified in 326 IAC 3-7-2(c), 326 IAC 3-7-2(d), and 326 IAC 3-7-2(e). Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.
(2) If fuel oil is fired in the unit during the CEMS downtime, pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, oil sampling and analysis data shall be collected as follows:

(A) The Permittee may rely upon vendor analysis of fuel delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

(B) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 326 IAC 3-7-4(a).

D.1.18 Visible Emissions Notations

(a) Daily visible emission notations of the exhaust from the bin vent filters on the storage silos shall be performed during normal daylight operations when loading or unloading material. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, at least eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.1.19 Broken or Failed Bin Vent Filter Detection

In the event that filter failure has been observed, for single compartment filters, failed units and the associated process will be shut down as soon as possible until the failed units have been repaired or replaced.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.20 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity, Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.1.2, D.1.4, D.1.13, and D.1.16, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Section C - Opacity and Conditions D.1.2, and D.1.4.

(1) Data and results from the most recent stack test.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6, 40 CFR 60.7, and 40 CFR 60.45.

(3) The results of all Method 9 visible emission readings taken during any periods of COM downtime.

(4) All ESP parametric monitoring readings.
(b) To document the compliance status with the SO$_2$ requirements in Conditions D.1.2(a), D.1.14, D.1.15, and D.1.17, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the applicable SO$_2$ limit(s) as required in Conditions D.1.2(a), D.1.14, and D.1.15. The Permittee shall maintain records in accordance with (3) and (4) below during SO$_2$ CEMS malfunction or downtime.

1. All SO$_2$ continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g), 40 CFR 60.7, and 40 CFR 60.45.

2. Actual fuel usage since last compliance determination period.

3. All fuel sampling and analysis data collected for SO$_2$ CEMS downtime, in accordance with Condition D.1.17.

4. Actual fuel usage during each SO$_2$ CEMS downtime.

(c) To document the compliance status with the NO$_x$ requirements in Condition D.1.14, the Permittee shall maintain records of all NO$_x$ and CO$_2$ or O$_2$ continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 2-2, 40 CFR 60.7, and 40 CFR 60.45. Records shall be complete and sufficient to establish compliance with the NO$_x$ limits as required in 40 CFR 60, Subpart D.

(d) To document the compliance status with Condition D.1.18, the Permittee shall maintain records of the visible emission notations required by that condition. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(e) To document the compliance status with the PSD minor limits in Condition D.1.3, the Permittee shall maintain records of the monthly heat input from Boiler MB1, Boiler MB2, all the Dry Sorbent and PAC delivered to the source and the amount of dry ash and wet ash loaded to and from the Ash Silos. Records shall be complete and sufficient to establish compliance with the PSD minor limits as required in Condition D.1.3.

(f) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.1.21 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document the compliance status with the PM and SO2 requirements of Conditions D.1.2, D.1.4, and D.1.15 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(35).

(b) Pursuant to 326 IAC 12, 40 CFR 60.7(c), Approval to Construct EPA-5-78-A-1, and 40 CFR 52.21, to document the compliance status with Condition D.1.2 and pursuant to 40 CFR 60.45(g), excess emissions and monitoring system performance (MSP) reports shall be submitted on a quarterly basis. All reports shall be postmarked by the 30th day following the end of each quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c). These reports shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee’s obligations with regard to the reporting required by this condition.

(c) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

1. Date of downtime.
2. Time of commencement.
3. Duration of each downtime.
4. Reasons for each downtime.
5. Nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee’s obligations with regard to the reporting required by this condition.

(d) A quarterly report of the total amount of Dry Sorbent delivered to the source to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee’s obligations with regard to the reporting required by this condition.

(e) A quarterly report of the total amount of PAC delivered to the source to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee’s obligations with regard to the reporting required by this condition.

(f) A quarterly report of the total amount of dry ash loaded to the ash silos to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee’s obligations with regard to the reporting required by this condition.

(g) A quarterly report of the total amount of wet ash loaded from the ash silos to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using
the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(h) A quarterly report of the total PM emissions from Boiler MB1 and Boiler MB2 to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(i) A quarterly report of the total PM10 emissions from Boiler MB1 and Boiler MB2 to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(j) A quarterly report of the total PM2.5 emissions from Boiler MB1 and Boiler MB2 to document the compliance status with PSD minor limits in Condition D.1.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description** [326 IAC 2-7-5(14)]

(c) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

[These are affected units under 40 CFR 60, Subpart D]
[These are affected units under 40 CFR 63, Subpart DDDDD]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

**Emission Limitations and Standards** [326 IAC 2-7-5(1)]

D.2.0 Limited Use Boiler [326 IAC 2-2] [40 CFR Part 63.7500(c) and 63.7575, Subpart DDDDD]

Beginning January 31, 2016, each auxiliary boiler shall be limited to less than 3773.06 Kilogallons of No. 2 fuel oil per twelve (12) consecutive month period, with compliance determined at the end of each month.

Completion with this limit will make the boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2 limited use boilers pursuant to 40 CFR 63.7500(c).

D.2.1 Alternative Opacity Monitoring [326 IAC 12][40 CFR 60.13(i)(2)]

Pursuant to the approval letter issued March 18, 2003, by U.S. EPA, and 40 CFR 60.13(i)(2), Auxiliary Boilers 1 and 2 shall comply with the following Alternative Opacity Monitoring requirements:

(a) Neither boiler shall be operated more than 876 hours in a calendar year. If one of the boilers is operated more than 876 hours in a calendar year, AEP shall immediately submit a schedule for installing and certifying a continuous opacity monitor (COM) to IDEM and U.S. EPA. This schedule shall require installation of the COM within six months or less of the 876 hour limit exceedance. IDEM and U.S. EPA shall also be immediately notified that the 876 hour limit has been exceeded.

(b) At least once every four (4) hours of operation, during daylight hours, an observer certified in accordance with U.S. EPA Method 9 shall perform three (3) six-minute observations of each boiler stack.

(c) If the average of any 6-minute set of readings collected in accordance with Condition D.2.1(b) exceeds 10 percent (10%), the observer must collect two additional 6-minute sets of visible emission readings.

(d) AEP shall maintain the boilers in accordance with good air pollution control practices.

D.2.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation of 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period. [326 IAC 5-1-3(a)].
D.2.3 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO2 emissions from Auxiliary Boilers 1 and 2 shall not exceed 0.5 pounds per million Btu (lbs/MMBtu).

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.2.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 12][40 CFR 60, Subpart D]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 40 CFR 60.45, no continuous emission monitoring systems are required for Auxiliary Boilers 1 and 2 at this time.

(a) Pursuant to paragraph (b) of 40 CFR 60.45:

(1) For a fossil fuel fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis.

(2) Pursuant to 40 CFR 60.45(b)(3) and the results of the nitrogen oxides (NOX) stack tests performed January 15 and January 16, 2003, Auxiliary Boilers 1 and 2 are exempted from the NOX continuous monitoring requirement of 60.45(a).

This exemption is contingent upon continued demonstration that the NOX emissions are less than 70% of the limit (i.e. < 0.21 pounds per million Btu's).

(3) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraph (b) of 40 CFR 60.45, a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(b) Pursuant to 40 CFR 60.13(i)(2), Auxiliary Boilers 1 and 2 shall comply with the Alternative Opacity Monitoring requirements of the approval letter issued March 18, 2003, by U.S. EPA, in lieu of the continuous opacity monitoring requirements of 40 CFR 60.45.

D.2.5 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

Performance tests for Auxiliary Boiler 1 and 2 were performed in 2003 pursuant to 40 CFR 60.11. PM and NOX stack testing shall be repeated using methods as approved by the Commissioner, as follows:

(a) By December 31 of the second calendar year following the most recent stack test; or

(b) If a unit is not operated at least 1,000 hours in the 2 years since the previous stack test, then testing shall be repeated at least once every 1,000 hours of operation for that unit, or five (5) calendar years from the date of the last valid compliance demonstration, whichever occurs first.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

D.2.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7][326 IAC 7-2][326 IAC 12][40 CFR 60.45(b)(2)]

(a) Pursuant to 40 CFR 60.45(b)(2), the Permittee shall monitor sulfur dioxide emissions by fuel sampling and analysis.
(b) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of 0.5 pounds per MMBtu, using a calendar month average.

(c) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, fuel sampling and analysis data shall be collected as follows:

1. The Permittee may rely upon vendor analysis of fuel shipments, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; the certification may apply to all trucks that are part of a single shipment as ordered by the Permittee; or,

2. The Permittee shall perform sampling and analysis of fuel oil samples in accordance with one of the following methods:

   A. Oil samples shall be collected from the tanker truck load prior to transferring fuel to the storage tank; or

   B. Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank; or

   C. Oil samples shall be collected on a monthly basis at the triplex pump station on the feed lines from the main oil storage tank to determine the fuel oil characteristics for the fuel oil used in Auxiliary Boiler #1 and Auxiliary Boiler #2.

(d) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.2.7 Record Keeping Requirements

(a) Pursuant to the approval letter issued March 18, 2003, by U.S. EPA, and 40 CFR 60.13(i)(2), and to document the compliance status with Section C - Opacity, Condition D.2.1(b) and (c), and Condition D.2.2 the Permittee shall maintain the following records:

1. Records of the date and time of visible emission observations, along with the results of each observation, must be maintained. Such records must be maintained on-site for a period of five years from the date of the observation.

2. Records of hours of operation for each boiler must be maintained onsite for a period of five years.

(b) To document the compliance status with the PM and NOx requirements in Condition D.2.5, the Permittee shall maintain records of the data and results from the most recent stack test. Records shall be complete and sufficient to establish compliance with the PM and NOx limits established in Condition D.2.5.

1. Data and results from the most recent stack test;

2. All sampling and analysis data used to show compliance with [40 CFR 60.42(a)(1)], [326 IAC 6-2-1(f)], and [40 CFR 60.44(a)(2)].
In order to document the compliance status with the SO₂ requirements in Conditions D.2.3 and D.2.6, the Permittee shall maintain records in accordance with (1) and (2) below.

Records shall be complete and sufficient to establish compliance with the SO₂ limits in Condition D.2.3.

(1) All fuel sampling and analysis data used to show compliance with 326 IAC 7-1.1 and 40 CFR 60.43(a)(1).

(1) Actual fuel usage since last compliance determination period.

Beginning January 31, 2016, in order to document the compliance status with Condition D.2.0, the Permittee shall maintain monthly records of no. 2 fuel oil usage.

Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

To document the compliance status with the applicable opacity limitations and monitoring requirements:

(1) Pursuant to the approval letter issued March 18, 2003, by U.S. EPA, and 40 CFR 60.13(i)(2), within thirty days of the end of each calendar quarter, excess opacity emission reports for Auxiliary Boilers 1 and 2 must be submitted to IDEM and U.S. EPA. The excess emission reports shall identify the number of hours of operation in that quarter, the number of hours of operation in previous quarters within the same calendar year, the total number of observations performed under condition D.2.1(b) and any excess opacity readings observed. The excess emission report shall denote that the boilers must comply with a 20 percent opacity limit over a six-minute average.

(2) Within thirty days of the end of each calendar quarter, a quarterly summary of the information to document compliance with Condition D.2.4 and 326 IAC 5-1-3 shall be submitted to IDEM at the address listed in Section C - General Reporting Requirements, of this permit, no later than thirty (30) days after the end of the quarter being reported.

The Permittee may elect to combine the excess opacity emission report for 326 IAC 5-1-3 with the quarterly reports required under part (a)(1) of this condition. If the Permittee elects to submit combined opacity reports, the reports submitted pursuant to (a) must also identify any excess opacity readings observed during startup and shutdown, and each report must state precisely which state and federal requirements are satisfied by the report.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
(3) The reports required by subparagraph (a)(1) of this Condition shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) To document compliance with the NSPS SO2 requirements:

(1) To document compliance with NSPS SO2 requirements, pursuant to 40 CFR 60.45(b)(2), excess SO2 emissions reports shall be submitted to the administrator semi-annually for each six month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c).

(2) The reports required by subparagraph (b)(1) of this Condition shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Upon request of the IDEM, OAQ, reports of the calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit. [326 IAC 7-2-1(c)(3]

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Beginning January 31, 2016, a quarterly report of the information to document the compliance status with Condition D.2.0 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
Emissions Unit Description [326 IAC 2-7-5(14)]

(d) A coal storage and handling system for MB1 and MB2, with installation started in 1981 and completed in 1984, consisting of the following equipment:

1. Two (2) barge unloading stations, identified as Stations 1 and 2, each with a baghouse, or a dust extraction system using water injection, and foam or water spray for particulate control, each with a bucket elevator with foam or water spray and partial enclosure for particulate control, and Conveyors 1 and 2 with water spray for particulate control.

2. Enclosed conveyor systems, including fully and partially enclosed conveyors, with foam, water, or other equivalent dust suppression measures for particulate control, with the transfer points enclosed by buildings with baghouses, or a dust extraction system using water injection, for particulate control at Stations 5, 6 and 7. A stacker reclaim system is used to drop coal to the storage pile(s). The coal handling system has a design throughput capacity of 4000 tons per hour up to the stacker-reclaimers, and 1600 tons per hour from Station 7E and 7W to the coal bunkers in the units.

3. Coal storage pile(s), with fugitive dust emissions controlled by watering.

4. Coal crushing Station 8, with a maximum throughput of 2618 tons per hour for the east system and 2542 tons per hour for the west system, with a baghouse for particulate control, or a dust extraction system using water injection.

5. Blending and transfer Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

6. Blending and transfer Station 10.

7. Two (2) storage silos for Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

8. Coal sampling and transfer Stations A and D, each with a baghouse for particulate control, or a dust extraction system using water injection.

9. Bunkering conveyors AB, BC, CB, DC, and FD, each fully enclosed, each with a baghouse for particulate control, or a dust extraction system using water injection.

10. Fourteen (14) storage silos for Unit 1, with particulate control as follows:
   (A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 1, or
   (B) one or more dust extraction systems using water injection.

11. Fourteen (14) storage silos for Unit 2, with particulate control as follows:
   (A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 2, or
   (B) one or more dust extraction systems using water injection.
Insignificant Activities [326 IAC 2-7-1(21)]:

Coal bunker and coal scale exhausts and associated dust collector vents.

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge loading, and enclosed conveyors 5, 6, and 7</td>
<td>4000</td>
<td>96.95</td>
</tr>
<tr>
<td>Transfer Station 7E and 7W, Station 9, Station 10, Transfer Station A&amp;D, enclosed conveyors AB, BC, CB, DC, and FD, and silos at Unit 1 and 2</td>
<td>1600</td>
<td>83.82</td>
</tr>
<tr>
<td>The east system of Station 8</td>
<td>2618</td>
<td>90.71</td>
</tr>
<tr>
<td>The west system of Station 8</td>
<td>2542</td>
<td>90.30</td>
</tr>
</tbody>
</table>

These pounds per hour limitations were calculated using the following equation for Interpolation and extrapolation for the process weight rate in excess of 60,000 pounds per hour:

\[ E = 55.0 \cdot P^{0.11} - 40 \]

where \( E \) = rate of emission in pounds per hour; and \( P \) = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the coal storage and handling system other than the coal storage piles, at a throughput rate greater than 200 tons per hour, the concentration of particulate may exceed the numerical limits in subparagraph (a), provided that particulate concentration in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.3.2 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, in order to comply with Condition D.3.1, the coal handling operations shall be conducted in enclosed operations, except for the coal barge unloading areas, coal storage piles and the coal yard handling areas between coal handling stations 6 and 7, which shall be controlled by a foam, water, or equivalent dust suppression system on as-needed basis to minimize fugitive dust.
Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.3.3 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the partially enclosed coal unloading stations shall be performed once per week during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the exhaust from the particulate control devices on the coal handling operations shall be performed once per week during normal daylight operations when the associated processes are in operation. A trained employee shall record whether emissions are normal or abnormal.

(c) If abnormal emissions are observed from the coal handling operations, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

(d) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(e) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.3.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.3.3 the Permittee shall maintain records of the weekly visible emission notations of the coal unloading station openings and the exhausts from the particulate control devices on the coal handling operations. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g., the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.
Emissions Unit Description [326 IAC 2-7-5(14)]

(e) Dry fly ash handling:

(1) Fly ash handling for MB1, installed in approximately 1982, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by a bin vent filter on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.

(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.

(2) Fly ash handling for MB2, with installation completed in 1986, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by two (2) bin vent filters on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.

(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.

(3) One (1) fly ash barge loading facility, with pneumatic unloading system from covered truck to covered barge with a maximum throughput rate of 52.5 tons ash per hour, with a baghouse (ABL-001) on a river cell for particulate control.

(4) Rail loading equipment associated with the former fly ash temporary storage facility, with a maximum throughput rate of 52.5 tons ash per hour. The loader has a baghouse for dust control (ADL-001).
Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes):

Summary of Process Weight Rate Limits

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>The fly ash vacuum conveying system to storage silos</td>
<td>58</td>
<td>46</td>
</tr>
<tr>
<td>The ash loading to open trucks from the storage silos</td>
<td>150</td>
<td>55</td>
</tr>
<tr>
<td>Fly ash barge loading</td>
<td>52.5</td>
<td>45</td>
</tr>
<tr>
<td>Fly ash rail loading</td>
<td>50</td>
<td>45</td>
</tr>
</tbody>
</table>

These pounds per hour limitations were calculated using the following equation:

\[ E = 55.0 \times P^{0.11} - 40 \]

where \( E \) = rate of emission in pounds per hour; and \( P \) = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash loading to tanker trucks from the storage silos at a maximum throughput rate greater than 200 tons per hour, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

D.4.2 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)] [40 CFR 64]

(a) Visible emission notations of the ash silo unloading station openings shall be performed at least once per day during normal daylight operations when ash is being unloaded. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of each ash silo bin vent filter exhaust, barge and rail loading baghouse exhaust, and the nozzle of each telescoping chute at the barge and rail loading stations shall be performed at least once per week during normal daylight operations when the respective ash silo bin vent filter or barge and rail loading are in operation. A trained employee shall record whether emissions are normal or abnormal.

(c) If abnormal emissions of ash are observed from the ash silo unloading station openings, the Permittee shall take reasonable response steps. Observation of visible emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.
(d) If abnormal emissions are observed at a bin vent filter or baghouse exhaust or from the nozzle of the telescoping chute, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

(e) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(f) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

D.4.3 Broken or Failed Bag Detection [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)] [40 CFR 64]

For a single compartment baghouse controlling emissions from the fly ash barge loading facility (ABL-001) and the rail loader associated with the former fly ash temporary storage facility (ADL-001), a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

Bag failure may be indicated by a significant drop in the baghouses' pressure reading, by abnormal visible emissions, by an opacity violation, or by visual inspection.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.4.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.4.2, the Permittee shall maintain records of the visible emission notations of the ash silo unloading station openings and the baghouse and bin vent exhausts. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g., the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.
### EMISSIONS UNIT DESCRIPTION

**Emissions Unit Description** [326 IAC 2-7-5(14)]

- (f) Wet process bottom ash handling, with hydroveyors conveying ash to storage ponds, with water level sufficient to prevent ash re-entrainment.

- (g) Paved Roads

### INSIGNIFICANT ACTIVITIES

**Insignificant Activities** [326 IAC 2-7-1(21)]:

- Ponded bottom ash handling and management, including dredging bottom ash ponds and loading material into trucks.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

### COMPLIANCE MONITORING REQUIREMENTS

**Compliance Monitoring Requirements** [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

#### D.5.1 Visible Emissions Notations

- (a) Visible emission notations of the bottom ash storage pond area(s) and any bottom ash storage piles shall be performed at least once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

- (b) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

- (c) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

### RECORD KEEPING AND REPORTING REQUIREMENTS

**Record Keeping and Reporting Requirements** [326 IAC 2-7-5(3)][326 IAC 2-7-19]

#### D.5.2 Record Keeping Requirements

- (a) To document the compliance status with Conditions C.5 and D.5.1, the Permittee shall maintain records of visible emission notations of the ash storage pond area(s) and any bottom ash storage piles. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation (e.g., the process did not operate that day).

- (b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.
SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]

(g) Emergency generators as follows: Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, constructed in 1983/1984, each with 25.16 MMBtu/hr heat input capacity.

(h) Five (5) No. 2 fuel oil-fired space heaters designated as WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9, with heat input capacities of 4.5 MMBtu/hr, 3.0 MMBtu/hr, 2.75 MMBtu/hr, 3.5 MMBtu/hr, and 4.5 MMBtu/hr, respectively.

(i) One (1) No. 2 fuel oil-fired space heater, identified as WHU-10, approved in 2018 for construction, with heat input capacity of 2.4 MMBtu/hr.

Insignificant Activities [326 IAC 2-7-1(21)]:

Space heaters using the following fuels: Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than three-tenths (0.3) percent sulfur by weight, including space heaters WHU-1 and WHU-2, each with 1.1 MMBtu/hr heat input capacity.

Emergency generators as follows: Diesel generators not exceeding 1600 horsepower.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 PSD Minor Limit [326 IAC 2-2]

In order to make the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to the diesel generators DG1, DG2, and DG3, during periods when both of the Unit 1 and Unit 2 main boilers are in service the total operating hours for all three diesel generators (DG1, DG2, and DG3) taken together shall not exceed 780 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

D.6.2 Sulfur Dioxide (SO2) [326 IAC 7]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO2 emissions from the distillate oil-fired emergency generators and space heaters shall not exceed 0.5 pounds per million Btu (lbs/MMBtu).

D.6.3 PSD Minor Limit for SO2 [326 IAC 2-2]

In order to make the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to the fuel oil-fired space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, WHU-9, and WHU-10:

The emissions from the heaters shall be limited to less than forty (40) tons of sulfur dioxide (SO2) per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with the above limit, shall limit the potential to emit of SO2 to less than 40 tons per year, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to this modification.
Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.6.4 Compliance Determination Equation

In order to comply with Condition D.6.3 – PSD Minor Limits, emissions shall be determined from the following equations:

\[
\text{SO}_2 \text{ Emissions} = \frac{142 \times S\% \times 22.65 \text{ MMBtu/hr} \times Hr \ (\text{hrs/month})}{\text{H} \ (\text{MMBtu/kgal}) \times 2000 \ (\text{lb/ton})}
\]

Where:
- \(\text{SO}_2 \text{ Emission Limit (S)} = (142 \times S\%) \text{ lbs per kilogallons}\)
- Monthly Average Sulfur Content = S (\%)
- Heat Input Capacity = 22.65 MMBtu/hr
- Operating Hours = Hr (hrs/month)
- Monthly Average Fuel Heating Value = H (MMBtu/kgal)

D.6.5 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3][326 IAC 7-2][326 IAC 7-1.1-2][326 IAC 2-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from the emergency generators do not exceed the equivalent of five-tenths (0.5) pound per million Btu heat input, using a calendar month average.

(b) The Permittee shall demonstrate that the fuel oil sulfur content does not exceed the percentage required for compliance with D.6.3.

(c) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, fuel sampling and analysis data shall be collected as follows:

(1) The Permittee may rely upon vendor analysis of fuel shipments, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; the certification may apply to all trucks that are part of a single shipment as ordered by the Permittee; or,

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with one of the following methods.

(A) Oil samples shall be collected from the tanker truck load prior to transferring fuel to the storage tank; or

(B) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank; or

(C) For the emergency diesel generators, oil samples shall be collected on a monthly basis at the triplex pump station on the feed lines from the main oil storage tank to determine the fuel oil characteristics for the fuel oil used in the emergency generators; or

(D) For the space heaters, oil samples shall be collected in monthly basis from the feed lines from the individual space heater fuel oil storage tanks between the storage tanks and the space heater.

Record Keeping and Reporting Requirement [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.6.6 Record Keeping Requirements

(a) To document the compliance status with the requirements in Condition D.6.1, the
Permittee shall maintain records of the following for each month of any one of the diesel generators:

(1) Identification of generator(s) in service.

(2) Total generator hours of operation (example: two generators operating for 3 hours equals 6 generator hours)

(3) The status of the Main Boilers MB1 and MB2 during periods of diesel generator operation.

(b) To document the compliance status with the requirements in Conditions D.6.2 and D.6.3, the Permittee shall maintain records of all fuel sampling and analysis data, pursuant to 326 IAC 7-2. Records shall be complete and sufficient to establish compliance with the limits in Conditions D.6.2 and D.6.3.

(c) To document the compliance status with the requirements in Condition D.6.3, the Permittee shall maintain records of all periods of operation of space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, WHU-9, and WHU-10. These records shall include the total cumulative operating time (in hours) for that calendar month.

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.6.7 Reporting Requirements

A quarterly report of the information to document the compliance status with Conditions D.6.1 and D.6.3 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
### Emissions Unit Description [326 IAC 2-7-5(14)]

**Insignificant Activities [326 IAC 2-7-1(21)]:**

Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

Cleaners and solvents characterized as follows:

1. Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;
2. Having a vapor pressure equal to or less than 0.7 kPa; 5mm Hg; or 0.1 psi measured at 20°C (68°F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

### Emission Limitations and Standards [326 IAC 2-7-5(1)]

**D.7.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]**

(a) Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaning degreasers without remote solvent reservoirs constructed after July 1, 1990:

1. Equip the degreaser with a cover.
2. Equip the degreaser with a device for draining cleaned parts.
3. Close the degreaser cover whenever parts are not being handled in the degreaser.
4. Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.
5. Provide a permanent, conspicuous label that lists the operating requirements in (a)(3), (a)(4), (a)(6), and (a)(7) of this condition.
6. Store waste solvent only in closed containers.
7. Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) The Permittee shall ensure the following additional control equipment and operating requirements are met:

1. Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):
   
   
   (A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.
(B) A water cover when solvent used is insoluble in, and heavier than, water.

(C) A refrigerated chiller.

(D) Carbon adsorption.

(E) An alternative system of demonstrated equivalent or better control as those outlined in (b)(1)(A) through (D) of this condition that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:

(A) must be a solid, fluid stream; and

(B) shall be applied at a pressure that does not cause excessive splashing.

D.7.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure than exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.7.3 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-3-8(c)(2), the following records shall be maintained for each purchase of cold cleaner degreaser solvent:

(1) The name and address of the solvent supplier.
(2) The date of purchase (or invoice/bill dates of contract servicer indicating service date).
(3) The type of solvent purchased.
(4) The total volume of the solvent purchased.
(5) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(b) Section C - General Record Keeping Requirements of this permit contains the Permittee’s obligations with regard to the records required by this condition.
Emissions Unit Description [326 IAC 2-7-5(14)]

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[This is an affected unit under 40 CFR 63, Subpart UUUUU]
[This is an affected unit under 40 CFR 60, Subpart D]

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[This is an affected unit under 40 CFR 63, Subpart UUUUU]
[This is an affected unit under 40 CFR 60, Subpart D]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program
E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)][326 IAC 21][40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78. The Acid Rain permit for this source is attached to this permit as Attachment B, and is incorporated by reference.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)][326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.
Emissions Unit Description: [326 IAC 2-7-5(14)]

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[bThis is an affected unit under 40 CFR 63, Subpart UUUUU]
[bThis is an affected unit under 40 CFR 60, Subpart D]

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[bThis is an affected unit under 40 CFR 63, Subpart UUUUU]
[bThis is an affected unit under 40 CFR 60, Subpart D]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

(a) Pursuant to 40 CFR 63.10040, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the above listed emissions units, as specified in 40 CFR Part 63, Subpart UUUUU, in accordance with the schedule in 40 CFR Part 63, Subpart UUUUU.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana  46204-2251

E.2.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU]

Pursuant to 40 CFR Part 63, Subpart UUUUU, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart UUUUU, (included as Attachment E to this permit), for the above listed emissions units, as specified as follows.

(a) 40 CFR 63.9980
(b) 40 CFR 63.9981
(c) 40 CFR 63.9982(a)(1) and (d)
(d) 40 CFR 63.9984(b), (c), and (f)
(e) 40 CFR 63.9991(a)
(f) 40 CFR 63.10000(a), (b), (c), (d), (e), and (l)
(g) 40 CFR 63.10005(a), (b), (d), (e), (f), (h), (j), and (k)
(h) 40 CFR 63.10006(b), (d), (f), (h), (j)(1), and (j)
(i) 40 CFR 63.10007(a), (b), (d), (e), and (g)
(j) 40 CFR 63.10009(k) and (m)
(k) 40 CFR 63.10010(a)(2)(ii), (b), (c), (d), (g), and (l)
(l) 40 CFR 63.10011(a), (c)(1), (d), (e), and (g)
(m) 40 CFR 63.10020
(n) 40 CFR 63.10021
(o) 40 CFR 63.10030
(p) 40 CFR 63.10031
(q) 40 CFR 63.10032
(r) 40 CFR 63.10033
(s) 40 CFR 63.10040
(t) 40 CFR 63.10041
(u) 40 CFR 63.10042
(v) Table 2 to 40 CFR 63, Subpart UUUUU
(w) Table 3 to 40 CFR 63, Subpart UUUUU
(x) Table 5 to 40 CFR 63, Subpart UUUUU
(y) Table 7 to 40 CFR 63, Subpart UUUUU
(z) Table 8 to 40 CFR 63, Subpart UUUUU
(aa) Table 9 to 40 CFR 63, Subpart UUUUU
SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(c) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)
New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart D]
[326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the pulverized coal opposed wall fired dry bottom boilers, identified as MB1 and MB2 and the two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, except as otherwise specified in 40 CFR Part 60, Subpart D.

E.3.2 New Source Performance Standards for Standard of Performance for Fossil-Fuel-Fired Steam Generators [40 CFR Part 60, Subpart D] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart D, the Permittee shall comply with the provisions of New Source Performance Standards for Standard of Performance for Fossil-Fuel-Fired Steam Generators, which are incorporated by reference as 326 IAC 12, for the pulverized coal opposed wall fired dry bottom boilers, identified as MB1 and MB2 and the two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, as specified as follows:

(1) 40 CFR 60.40
(2) 40 CFR 60.41
(3) 40 CFR 60.42
(4) 40 CFR 60.43(a) and (b)
(5) 40 CFR 60.44(a) and (b)
(6) 40 CFR 60.45
(7) 40 CFR 60.46
Emissions Unit Description [326 IAC 2-7-5(14)]

(d) A coal storage and handling system for MB1 and MB2, with installation started in 1981 and completed in 1984, consisting of the following equipment:

1. Two (2) barge unloading stations, identified as Stations 1 and 2, each with a baghouse, or a dust extraction system using water injection, and foam or water spray for particulate control, each with a bucket elevator with foam or water spray and partial enclosure for particulate control, and Conveyors 1 and 2 with water spray for particulate control.

2. Enclosed conveyor systems, including fully and partially enclosed conveyors, with foam, water, or other equivalent dust suppression measures for particulate control, with the transfer points enclosed by buildings with baghouses, or a dust extraction system using water injection, for particulate control at Stations 5, 6 and 7. A stacker reclaim system is used to drop coal to the storage pile(s). The coal handling system has a design throughput capacity of 4000 tons per hour up to the stacker-reclaimers, and 1600 tons per hour from Station 7E and 7W to the coal bunkers in the units.

3. Coal storage pile(s), with fugitive dust emissions controlled by watering.

4. Coal crushing Station 8, with a maximum throughput of 2618 tons per hour for the east system and 2542 tons per hour for the west system, with a baghouse for particulate control, or a dust extraction system using water injection.

5. Blending and transfer Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

6. Blending and transfer Station 10.

7. Two (2) storage silos for Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

8. Coal sampling and transfer Stations A and D, each with a baghouse for particulate control, or a dust extraction system using water injection.

9. Bunkering conveyors AB, BC, CB, DC, and FD, each fully enclosed, each with a baghouse for particulate control, or a dust extraction system using water injection.

10. Fourteen (14) storage silos for Unit 1, with particulate control as follows:
   (A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 1, or
   (B) one or more dust extraction systems using water injection.

11. Fourteen (14) storage silos for Unit 2, with particulate control as follows:
   (A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 2, or
   (B) one or more dust extraction systems using water injection.
Insignificant Activities [326 IAC 2-7-1(21)]:

Coal bunker and coal scale exhausts and associated dust collector vents.

[These are affected units under 40 CFR 60, Subpart Y]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) [40 CFR 60, Subpart Y] [326 IAC 2-7-5(1)]

E.4.1 General Provisions Relating to NSPS [326 IAC 12-1][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the coal storage and handling system for MB1 and MB2, except when otherwise specified in 40 CFR Part 60, Subpart Y.

E.4.2 New Source Performance Standard (NSPS): Coal Preparation Plants [326 IAC 12]

[40 CFR 60, Subpart Y]

The following provisions of 40 CFR Part 60, Subpart Y - Standards of Performance for Coal Preparation Plants, which are incorporated by reference in 326 IAC 12, apply to the coal storage and handling system for MB1 and MB2 (Applicable portions are included in Attachment B):

(a) 40 CFR 60.250;
(b) 40 CFR 60.251;
(c) 40 CFR 60.252(a)(1), and (2), (b)(1) and (2), and (c);
(d) 40 CFR 60.253(a)(1), and (2)(i)(ii) and (b), and
(e) 40 CFR 60.254.
**SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS**

**Emissions Unit Description:**

| (g) | Emergency generators as follows: Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, constructed in 1983/1984, each with 25.16 MMBtu/hr heat input capacity.  
[These are affected units under 40 CFR 63, Subpart ZZZZ] |
| (j) | Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.  
[These are affected units under 40 CFR 60, Subpart IIII]  
[These are affected units under 40 CFR 63, Subpart ZZZZ] |

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

**National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-7-5(1)]**


Pursuant to 40 CFR 63.6590, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the affected source, as specified in Appendix A of 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63 Subpart ZZZZ.


Pursuant to CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63.6590, for the affected source, as specified as follows:

1. 40 CFR 63.6585
2. 40 CFR 63.6590(b)(3)(iii)
3. 40 CFR 63.6640(f)(2)
4. 40 CFR 63.6675
SECTION E.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]

(c) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

[These are affected units under 40 CFR 60, Subpart D]
[These are affected units under 40 CFR 63, Subpart DDDDD]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants [40 CFR 63] [326 IAC 2-7-5(1)]


Pursuant to 40 CFR 63.7565, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 unless otherwise specified in 40 CFR 63, Subpart DDDDD (National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters).


Beginning January 31, 2016, the Permittee which has industrial, commercial, and institutional boilers and process heaters shall comply with the applicable provisions of 40 CFR Part 63, Subpart DDDDD, which are incorporated by reference as 326 IAC 20-95, as follows: The full text of Subpart DDDDD will be found in Attachment D to this permit.

(1) 40 CFR 63.7485
(2) 40 CFR 63.7490(a)(1)
(3) 40 CFR 63.7490(d)
(4) 40 CFR 63.7495(b)
(5) 40 CFR 63.7499(o)
(6) 40 CFR 63.7500(c)
(7) 40 CFR 63.7500(f)
(8) 40 CFR 63.7501
(9) 40 CFR 63.7505(a)
(10) 40 CFR 63.7515(d)
(11) 40 CFR 63.7525(k)
(12) 40 CFR 63.7540(a)
(13) 40 CFR 63.7540(a)(12)
(14) 40 CFR 63.7550(b)
(15) 40 CFR 63.7550(c)(1)
(16) 40 CFR 63.7550(c)(5)(i) through (iv)
(17) 40 CFR 63.7550(c)(5)(xvi)
(18) 40 CFR 63.7550(h)(3)
(19) 40 CFR 63.7555(a)(1)
(20) 40 CFR 63.7555(i)
(21) 40 CFR 63.7555(j)
(22) 40 CFR 63.7560
(23) 40 CFR 63.7575
SECTION E.7  EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.

[These are affected units under 40 CFR 60, Subpart IIII]
[These are affected units under 40 CFR 63, Subpart ZZZZ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) [326 IAC 2-7-5(1)]

E.7.1 General Provisions Relating to New Source Performance Standards (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the above listed emissions units, except as otherwise specified in 40 CFR Part 60, Subpart III.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.7.2 Standard of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12] [40 CFR 60, Subpart III]

Pursuant to 40 CFR 60 Subpart III, the Permittee shall comply with the provisions of 40 CFR 60 Subpart III (included as Attachment H to this permit), which are incorporated by reference as 326 IAC 12, for DFP-1 and DFP-2, as specified as follows:

(1) 40 CFR 60.4202
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4207(a) & (b)
(4) 40 CFR 60.4209(a)
(5) 40 CFR 60.4211(a),(c) & (e)
(6) 40 CFR 60.4214(b)

E.7.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

ORIS Code: 6166

Transport Rule (TR):

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOX burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOX control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOX burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOX control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

G.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated...
representative, and may have an alternate designated representative, in accordance with the following:

(a) 40 CFR 97.413 through 97.418;
(b) 40 CFR 97.513 through 97.518; and
(c) 40 CFR 97.613 through 97.618.

G.2 Emissions monitoring, reporting, and recordkeeping requirements

The owners and operators, and the designated representative, of each TR NOX Annual source, TR NOx Ozone Season source, and TR SO2 Group 1 source, and each TR NOX Annual unit at the source, TR NOx Ozone Season unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.530, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.531, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.532, and 97.632 (monitoring system out-of-control periods), 97.433, 97.533, and 97.633 (notifications concerning monitoring), 97.434, 97.534, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.535, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(1) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NOx Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NOx Annual emissions limitation and assurance provisions under Condition G.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(2) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NOx Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NOx Ozone Season emissions limitation and assurance provisions under Condition G.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(3) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO2 Group 1 emissions limitation and assurance provisions under Condition G.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

G.3 NOX annual emissions requirements

TR NOX Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall hold, in the source's compliance account, TR NOx Annual
allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NOX emissions for such control period from all TR NOX Annual units at the source.

(ii). If total NOX emissions during a control period in a given year from the TR NOX Annual units at a TR NOX Annual source are in excess of the TR NOX Annual emissions limitation set forth in Condition G.3(1)(i) above, then:

(A). The owners and operators of the source and each TR NOX Annual unit at the source shall hold the TR NOX Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each TR NOX Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NOX Annual assurance provisions.

(i). If total NOX emissions during a control period in a given year from all TR NOX Annual units at TR NOX Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such NOX emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOX Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying—

(A) The quotient of the amount by which the common designated representative’s share of such NOX emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such NOX emissions exceeds the respective common designated representative’s assurance level; and

(B) The amount by which total NOX emissions from all TR NOX Annual units at TR NOX Annual sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NOX Annual allowances required under Condition G.3(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NOX emissions from all TR NOX Annual units at TR NOX Annual sources in the State during a control period in a given year exceed the state assurance level if such total NOX emissions exceed the sum, for such control period, of the state NOx Annual trading budget under 40 CFR 97.410(a) and the state’s variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NOX emissions from all TR NOX Annual units at TR NOX Annual sources in the State during a control period exceed the state assurance level or if
a common designated representative's share of total NOx emissions from the TR NOx Annual units at TR NOx Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NOx Annual allowances for a control period in a given year in accordance with Condition G.3(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOx Annual allowance that the owners and operators fail to hold for such control period in accordance with Condition G.3(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A TR NOx Annual unit shall be subject to the requirements under Condition G.3(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A TR NOx Annual unit shall be subject to the requirements under Condition G.3(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Annual allowance held for compliance with the requirements under Condition G.3(1)(i) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NOx Annual allowance held for compliance with the requirements under Condition G.3(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NOx Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NOx Annual allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR NOx Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
Property right. A TR NOx Annual allowance does not constitute a property right.

G.4 NOx ozone season requirements

TR NOx Ozone Season emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall hold, in the source’s compliance account, TR NOx Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Ozone Season units at the source.

(ii). If total NOx emissions during a control period in a given year from the TR NOx Ozone Season units at a TR NOx Ozone Season source are in excess of the TR NOx Ozone Season emissions limitation set forth in Condition G.4(1)(i) above, then:

(A). The owners and operators of the source and each TR NOx Ozone Season unit at the source shall hold the TR NOx Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

(B). The owners and operators of the source and each TR NOx Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) TR NOx Ozone Season assurance provisions.

(i). If total NOx emissions during a control period in a given year from all TR NOx Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such NOx emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOx Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(A). The quotient of the amount by which the common designated representative’s share of such NOx emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such NOx emissions exceeds the respective common designated representative’s assurance level; and
(B). The amount by which total NOx emissions from all TR NOx Ozone Season units at TR NOx Ozone Season sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NOx Ozone Season allowances required under Condition G.4(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NOx emissions from all TR NOx Ozone Season units at TR NOx Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NOx emissions exceed the sum, for such control period, of the State NOx Ozone Season trading budget under 40 CFR 97.510(a) and the state’s variability limit under 40 CFR 97.510(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NOx emissions from all TR NOx Ozone Season units at TR NOx Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative’s share of total NOx emissions from the TR NOx Ozone Season units at TR NOx Ozone Season sources in the state during a control period exceeds the common designated representative’s assurance level.

(v). To the extent the owners and operators fail to hold TR NOx Ozone Season allowances for a control period in a given year in accordance with Condition H.4(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOX Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance Periods.

(i). A TR NOx Ozone Season unit shall be subject to the requirements under Condition G.4(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.530(b) and for each control period thereafter.

(ii). A TR NOx Ozone Season unit shall be subject to the requirements under Condition G.4(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition G.4(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.
(ii). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition G.4(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowances Management System Requirements.

(i). Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBBB.

(6) Limited Authorization.

(i). A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and

(B). Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property Right.

(i). A TR NOx Ozone Season allowance does not constitute a property right.

G.5 SO2 emissions requirements

TR SO2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO2 emissions for such control period from all TR SO2 Group 1 units at the source.

(ii). If total SO2 emissions during a control period in a given year from the TR SO2 Group 1 units at a TR SO2 Group 1 source are in excess of the TR SO2 Group 1 emissions limitation set forth in Condition G.5(1)(i) above, then:

(A). The owners and operators of the source and each TR SO2 Group 1 unit at the source shall hold the TR SO2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each TR SO2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.
(2) TR SO₂ Group 1 assurance provisions

(i). If total SO₂ emissions during a control period in a given year from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such SO₂ emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO₂ Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative’s share of such SO₂ emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such SO₂ emissions exceeds the respective common designated representative’s assurance level; and

(B). The amount by which total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR SO₂ Group 1 allowances required under Condition G.5(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO₂ emissions exceed the sum, for such control period, of the state SO₂ Group 1 trading budget under 40 CFR 97.610(a) and the state’s variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative’s share of total SO₂ emissions from the TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the state during a control period exceeds the common designated representative’s assurance level.

(v). To the extent the owners and operators fail to hold TR SO₂ Group 1 allowances for a control period in a given year in accordance with Condition G.5(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR SO₂ Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Condition G.5(2)(i) through (iii) above and each day of such control period shall constitute a
(3) Compliance periods.

   (i). A TR SO\textsubscript{2} Group 1 unit shall be subject to the requirements under Condition H.5(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

   (ii). A TR SO\textsubscript{2} Group 1 unit shall be subject to the requirements under Condition H.5(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

   (i). A TR SO\textsubscript{2} Group 1 allowance held for compliance with the requirements under Condition G.5(1)(i) above for a control period in a given year must be a TR SO\textsubscript{2} Group 1 allowance that was allocated for such control period or a control period in a prior year.

   (ii). A TR SO\textsubscript{2} Group 1 allowance held for compliance with the requirements under Condition G.5(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR SO\textsubscript{2} Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO\textsubscript{2} Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO\textsubscript{2} Group 1 allowance is a limited authorization to emit one ton of SO\textsubscript{2} during the control period in one year. Such authorization is limited in its use and duration as follows:

   (i). Such authorization shall only be used in accordance with the TR SO\textsubscript{2} Group 1 Trading Program; and

   (ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO\textsubscript{2} Group 1 allowance does not constitute a property right.

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G.6 Title V Permit Revision Requirements

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NOX Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NOX Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBBB, and TR SO\textsubscript{2} Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous
emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

G.7 Additional recordkeeping and reporting requirements

Unless otherwise provided, the owners and operators of each TR NOX Annual source and each TR NOX Annual unit, TR NOX Ozone Season source and each TR NOX Ozone Season unit, and TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NOX Annual unit, TR NOX Ozone Season unit, and TR SO2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart BBBBB, and 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOX Annual Trading Program, TR NOX Ozone Season Trading Program, and TR SO2 Group 1 Trading Program.

(2) The designated representative of a TR NOX Annual source and each TR NOX Annual unit, a TR NOX Ozone Season source and each TR NOX Ozone Season unit, and a TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall make all submissions required under the TR NOX Annual Trading Program, TR NOX Ozone Season Trading Program, and TR SO2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

G.8 Liability

Any provision of the TR NOX Annual Trading Program that applies to a TR NOX Annual source or the designated representative of a TR NOX Annual source shall also apply to the owners and operators of such source and of the TR NOX Annual units at the source.

(1) Any provision of the TR NOX Annual Trading Program that applies to a TR NOX Annual unit or the designated representative of a TR NOX Annual unit shall also apply to the owners and operators of such unit.

(2) Any provision of the TR NOX Ozone Season Trading Program that applies to a TR NOX Ozone Season source or the designated representative of a TR NOX Ozone Season
source shall also apply to the owners and operators of such source and of the TR NO\textsubscript{x} Ozone Season units at the source.

(3) Any provision of the TR NO\textsubscript{x} Ozone Season Trading Program that applies to a TR NO\textsubscript{x} Ozone Season unit or the designated representative of a TR NO\textsubscript{x} Ozone Season unit shall also apply to the owners and operators of such unit.

(4) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 source or the designated representative of a TR SO\textsubscript{2} Group 1 source shall also apply to the owners and operators of such source and of the TR SO\textsubscript{2} Group 1 units at the source.

(5) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 unit or the designated representative of a TR SO\textsubscript{2} Group 1 unit shall also apply to the owners and operators of such unit.

G.9 Effect on other authorities

No provision of the TR NO\textsubscript{x} Annual Trading Program or exemption under 40 CFR 97.405, TR NO\textsubscript{x} Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO\textsubscript{2} Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO\textsubscript{x} Annual source or TR NO\textsubscript{x} Annual unit, TR NO\textsubscript{x} Ozone Season source or TR NO\textsubscript{x} Ozone Season unit, and TR SO\textsubscript{2} Group 1 source or TR SO\textsubscript{2} Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

G.10 Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NO\textsubscript{x} Annual Trading Program and TR NO\textsubscript{x} Ozone Season Trading Program and TR SO\textsubscript{2} Group 1 Trading Program.

| Unit ID: pulverized coal opposed wall fired dry bottom boiler, identified as MB1 |
|----------------------------------|-------------------------------|------------------|---------------|----------------------------------|
| Parameter | Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO\textsubscript{2} monitoring) and 40 CFR part 75, subpart H (for NO\textsubscript{x} monitoring) | Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D | Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E | Low Mass Emissions excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, 19 | EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E |
| SO\textsubscript{2} | x | | | | |
Unit ID: pulverized coal opposed wall fired dry bottom boiler, identified as MB2

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO₂ monitoring) and 40 CFR part 75, subpart H (for NOₓ monitoring)</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
<th>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</th>
<th>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19</th>
<th>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOₓ</td>
<td>x</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
</tr>
<tr>
<td>Heat input</td>
<td>x</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
</tr>
</tbody>
</table>
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Indiana Michigan Power Co. - Rockport Plant
Source Address: 2791 N US Highway 231, Rockport, Indiana 47635
Part 70 Permit No.: 147-40656-00020

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter
☐ Test Result (specify)
☐ Report (specify)
☐ Notification (specify)
☐ Affidavit (specify)
☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Phone:
Date:
This is an emergency as defined in 326 IAC 2-7-1(12)

- The Permittee must notify the Office of Air Quality (OAQ), no later than four (4) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile no later than two (2) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:

Control Equipment:

Permit Condition or Operation Limitation in Permit:

Description of the Emergency:

Describe the cause of the Emergency:
If any of the following are not applicable, mark N/A

<table>
<thead>
<tr>
<th>Date/Time Emergency started:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date/Time Emergency was corrected:</td>
</tr>
<tr>
<td>Was the facility being properly operated at the time of the emergency?</td>
</tr>
<tr>
<td>Type of Pollutants Emitted: TSP, PM-10, SO2, VOC, NOx, CO, Pb, other:</td>
</tr>
<tr>
<td>Estimated amount of pollutant(s) emitted during emergency:</td>
</tr>
<tr>
<td>Describe the steps taken to mitigate the problem:</td>
</tr>
<tr>
<td>Describe the corrective actions/response steps taken:</td>
</tr>
<tr>
<td>Describe the measures taken to minimize emissions:</td>
</tr>
<tr>
<td>If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:</td>
</tr>
</tbody>
</table>

Form Completed by: __________________________
Title / Position: ____________________________
Date: ____________________________
Phone: ____________________________

A certification is not required for this report.
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  

Part 70 Quarterly Report  
Auxiliary Boiler Hours of Operation  

Source Name: Indiana Michigan Power Co. - Rockport Plant  
Source Address: 2791 N US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: 147-40656-00020  
Facility: Auxiliary Boilers 1 and 2  
Parameter: NSPS Alternate Opacity Monitoring Approval  
Limit: Neither boiler shall be operated more than 876 hours in a calendar year.  

<table>
<thead>
<tr>
<th>Month</th>
<th>Hours of operation for each Auxiliary Boiler</th>
<th>Hours of Operation in this Calendar Year, for each Auxiliary Boiler</th>
<th>Hours of operation for each Auxiliary Boiler</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>This Month</td>
<td>Previous 11 Months</td>
</tr>
<tr>
<td>Month 1</td>
<td></td>
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<td></td>
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<tr>
<td>Month 2</td>
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<tr>
<td>Month 3</td>
<td></td>
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</tr>
</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
   Deviation has been reported on:  

Submitted by: ________________________________  
Title / Position: ________________________________  
Signature: ________________________________  
Date: ________________________________  
Phone: ________________________________
**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**  
**OFFICE OF AIR QUALITY**  
**Compliance and Enforcement Branch**

**Part 70 Quarterly Report: Emergency Generators Hours of Operation**

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: Diesel Generators DG1, DG2, DG3  
Parameter: Hours of Operation  
Limits: Shall not exceed 780 hours total per twelve (12) consecutive month period.

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH Hours of operation for each generator</th>
<th>THIS MONTH Hours of generator operation when both main boilers were in operation</th>
<th>PREVIOUS 11 MONTHS TOTAL hours of generator operation when both main boilers were in operation</th>
<th>12 MONTH TOTAL hours of generator operation when both main boilers were in operation</th>
</tr>
</thead>
<tbody>
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</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
Deviation has been reported on: ___________________

Submitted by: _____________________________________________________  
Title / Position: _____________________________________________________  
Signature: _________________________________________________________  
Date: ____________________________________________________________  
Phone: ____________________________________________________________
Part 70 Quarterly Report: Space Heaters Hours of Operation

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facility: Space Heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, WHU-9, and WHU-10  
Parameter: Sulfur Dioxide (SO₂) emissions  
Limit: SO₂ emissions shall not exceed 40 tons per twelve (12) consecutive month period

<table>
<thead>
<tr>
<th>QUARTER</th>
<th>YEAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month</td>
<td>Total SO₂ This Month</td>
</tr>
<tr>
<td>Month 1</td>
<td></td>
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<tr>
<td>Month 2</td>
<td></td>
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<tr>
<td>Month 3</td>
<td></td>
</tr>
</tbody>
</table>

1. Facility consists of seven (7) No. 2 fuel oil fired space heaters  
2. Hours of operation Last 12 Months = Sum of Hours of Operation Over the Last 12 Months

- Supporting documents attached.  
- No deviation occurred in this quarter.  
- Deviation/s occurred in this quarter.  

Deviation has been reported on: __________________________  
Submitted by: _____________________________________________  
Title / Position: ___________________________________________  
Signature: ________________________________________________  
Date: ____________________________________________________  
Telephone: _______________________________________________
Part 70 Quarterly Report: Total Dry Sorbent delivered

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635
Part 70 Permit No.: T147-40656-00020
Facilities: Dry Sorbent Silos
Parameter: The Dry Sorbent delivered
Limits: The Dry Sorbent delivered to the site shall not exceed 142,500 tons per twelve (12) consecutive month period for both units.

YEAR: _____________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH Tons of Dry Sorbent Delivered</th>
<th>PREVIOUS 11 MONTHS TOTAL Tons of Dry Sorbent Delivered</th>
<th>12 MONTH TOTAL Tons of Dry Sorbent Delivered</th>
</tr>
</thead>
<tbody>
<tr>
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</tbody>
</table>

☐ No deviation occurred in this quarter.
☒ Deviation/s occurred in this quarter.
   Deviation has been reported on: ___________________

Submitted by: ______________________________________________________
Title / Position: ___________________________________________________
Signature: _________________________________________________________
Date: _____________________________________________________________
Telephone: _________________________________________________________
Part 70 Quarterly Report: Total PAC delivered

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635
Part 70 Permit No.: T147-29841-00020
Facilities: PAC Silos
Parameter: The PAC delivered

Limits: The PAC delivered to the site shall not exceed 35,040 tons per twelve (12) consecutive month period for both units.

<table>
<thead>
<tr>
<th>YEAR:</th>
<th>THIS MONTH</th>
<th>PREVIOUS 11 MONTHS</th>
<th>12 MONTH TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tons of PAC Delivered</td>
<td>Tons of PAC Delivered</td>
<td>Tons of PAC Delivered</td>
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</tbody>
</table>

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.

Deviation has been reported on: ___________________

Submitted by: ________________________________
Title / Position: ______________________________
Signature: ____________________________________
Date: _______________________________________
Telephone: ___________________________________
## Part 70 Quarterly Report: Dry Ash loaded to the Ash Silos

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: Ash Silos  
Parameter: Dry ash loaded  
Limits: The total amount of the dry ash loaded to the ash silos shall not exceed 583,742 per twelve (12) consecutive month period for both units.

YEAR: _____________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH Tons of Dry Ash Loaded</th>
<th>PREVIOUS 11 MONTHS TOTAL Tons of Dry Ash Loaded</th>
<th>12 MONTH TOTAL Tons of Dry Ash Loaded</th>
</tr>
</thead>
<tbody>
<tr>
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</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
   Deviation has been reported on: ___________________

Submitted by: ____________________________________________________  
Title / Position: __________________________________________________

Signature: ________________________________________________________  
Date: __________________________________________________________________  
Telephone: __________________________________________________________________


INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
Compliance and Enforcement Branch

Part 70 Quarterly Report: Wet Ash Loaded

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: Ash Silos  
Parameter: Wet ash loaded  
Limits: The total amount of wet ash loaded from the ash silos shall not exceed 686,846 per twelve (12) consecutive month period for both units.

YEAR: _____________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH Tons of Wet Ash Loaded</th>
<th>PREVIOUS 11 MONTHS TOTAL Tons of Wet Ash Loaded</th>
<th>12 MONTH TOTAL Tons of Wet Ash Loaded</th>
</tr>
</thead>
<tbody>
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</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
  Deviation has been reported on: ___________________

Submitted by: ______________________________________________________

Title / Position: ____________________________________________________

Signature: ________________________________________________________

Date: ____________________________________________________________

Telephone: _________________________________________________________
**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**  
**OFFICE OF AIR QUALITY**  
Compliance and Enforcement Branch

**Part 70 Quarterly Report: PM emissions from MB1 and MB2 common stack**

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: MB1 and MB2  
Parameter: PM emissions  
Limits: PM emissions from MB1 and MB2 common stack shall not exceed 2575 tons per twelve (12) consecutive month period.

YEAR: _____________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH PM emissions (tons)</th>
<th>PREVIOUS 11 MONTHS TOTAL PM emissions (tons)</th>
<th>12 MONTH TOTAL PM emissions (tons)</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
</tbody>
</table>

- □ No deviation occurred in this quarter.  
- □ Deviation/s occurred in this quarter.  
  Deviation has been reported on: ___________________

Submitted by: _____________________________________________________

Title / Position: ____________________________________________________

Signature: ________________________________________________________

Date: ____________________________________________________________

Telephone: ________________________________________________________
Part 70 Quarterly Report: PM emissions from MB1 and MB2 common stack

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: MB1 and MB2  
Parameter: PM10 emissions  
Limits: PM10 emissions from MB1 and MB2 common stack shall not exceed 1725 tons per twelve (12) consecutive month period.

YEAR: _____________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH PM10 emissions (tons)</th>
<th>PREVIOUS 11 MONTHS TOTAL PM10 emissions (tons)</th>
<th>12 MONTH TOTAL PM10 emissions (tons)</th>
</tr>
</thead>
<tbody>
<tr>
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</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
Deviation has been reported on: ___________________

Submitted by: _____________________________________________________  
Title / Position: ____________________________________________________  
Signature: ________________________________________________________  
Date: ____________________________________________________________  
Telephone: ________________________________________________________
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
Compliance and Enforcement Branch

Part 70 Quarterly Report: PM emissions from MB1 and MB2 common stack

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: T147-40656-00020  
Facilities: MB1 and MB2  
Parameter: PM2.5 emissions  
Limits: PM2.5 emissions from MB1 and MB2 common stack shall not exceed 746 tons per twelve (12) consecutive month period.

YEAR: ________________

<table>
<thead>
<tr>
<th>Month</th>
<th>THIS MONTH PM2.5 emissions (tons)</th>
<th>PREVIOUS 11 MONTHS TOTAL PM2.5 emissions (tons)</th>
<th>12 MONTH TOTAL PM2.5 emissions (tons)</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
</tbody>
</table>

☐ No deviation occurred in this quarter.  
☐ Deviation/s occurred in this quarter.  
   Deviation has been reported on: ________________

Submitted by: ________________________________
Title / Position: ________________________________
Signature: ______________________________________
Date: ______________________________________
Telephone: ____________________________________
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  

Part 70 Quarterly Report

Source Name: Indiana Michigan Power Co. - Rockport Plant  
Source Address: 2791 N US Highway 231, Rockport, Indiana 47635  
Part 70 Permit No.: 147-40656-00020  
Facility: Auxiliary Boiler 1  
Parameter: Fuel Usage  
Limit: less than 3773.06 kilogallons of no. 2 fuel oil per twelve (12) consecutive month period.

<table>
<thead>
<tr>
<th>QUARTER</th>
<th>YEAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month 1</td>
<td></td>
</tr>
<tr>
<td>Month 2</td>
<td></td>
</tr>
<tr>
<td>Month 3</td>
<td></td>
</tr>
</tbody>
</table>

- □ No deviation occurred in this quarter.
- □ Deviation/s occurred in this quarter.
  Deviation has been reported on:

Submitted by: ____________________________  
Title / Position: ____________________________  
Signature: ____________________________  
Date: ____________________________  
Phone: ____________________________
Part 70 Quarterly Report

Source Name: Indiana Michigan Power Co. - Rockport Plant
Source Address: 2791 N US Highway 231, Rockport, Indiana 47635
Part 70 Permit No.: 147-40656-00020
Facility: Auxiliary Boiler 2
Parameter: Fuel Usage
Limit: less than 3773.06 kilogallons of no. 2 fuel oil per twelve (12) consecutive month period.

<table>
<thead>
<tr>
<th>QUARTER</th>
<th>YEAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month 1</td>
<td></td>
</tr>
<tr>
<td>This Month</td>
<td>Previous 11 Months</td>
</tr>
<tr>
<td>Month 2</td>
<td></td>
</tr>
<tr>
<td>Month 3</td>
<td></td>
</tr>
</tbody>
</table>

- No deviation occurred in this quarter.

- Deviation/s occurred in this quarter.
  Deviation has been reported on:

Submitted by: ____________________________
Title / Position: ____________________________
Signature: ____________________________
Date: ____________________________
Phone: ____________________________
This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B – Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C - General Reporting. Proper notice submittal under Section B – Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C - General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

<table>
<thead>
<tr>
<th>Permit Requirement (specify permit condition #)</th>
<th>Date of Deviation:</th>
<th>Duration of Deviation:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Deviations:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Probable Cause of Deviation:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Response Steps Taken:</td>
<td></td>
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</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Permit Requirement (specify permit condition #)</th>
<th>Date of Deviation:</th>
<th>Duration of Deviation:</th>
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<tbody>
<tr>
<td>Number of Deviations:</td>
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<tr>
<td>Probable Cause of Deviation:</td>
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<tr>
<td>Response Steps Taken:</td>
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<tr>
<td>Permit Requirement (specify permit condition #)</td>
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<tr>
<td>Date of Deviation:</td>
<td>Duration of Deviation:</td>
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<td>Number of Deviations:</td>
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<tr>
<td>Probable Cause of Deviation:</td>
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<tr>
<td>Response Steps Taken:</td>
<td></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Permit Requirement (specify permit condition #)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date of Deviation:</td>
</tr>
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</tr>
<tr>
<td>Probable Cause of Deviation:</td>
</tr>
<tr>
<td>Response Steps Taken:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Permit Requirement (specify permit condition #)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date of Deviation:</td>
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<tr>
<td>Number of Deviations:</td>
</tr>
<tr>
<td>Probable Cause of Deviation:</td>
</tr>
<tr>
<td>Response Steps Taken:</td>
</tr>
</tbody>
</table>

Form Completed by: ________________________________
Title / Position: ________________________________
Date: _________________________________________
Phone: _________________________________________
Attachment A

Part 70 Operating Permit No: 147-40656-00020

[Downloaded from the eCFR on June 5, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.


§ 60.41 Definitions.

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

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

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see § 60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.
Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.


§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

1. Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

2. Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with § 60.42Da(a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.42Da(a) of subpart Da of this part.

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO2 or PM is exempt from the PM standards specified in paragraph (a) of this section.
§ 60.43 Standard for sulfur dioxide (SO2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO2 in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

\[
P_{SO2} = \frac{y}{100} P_{SO2_{liquid}} + \frac{z}{100} P_{SO2_{solid}}
\]

Where:

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

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

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

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.
(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

\[
P_{\text{NOx,prorated}} = \frac{w \times (260) + x \times (288) + y \times (130) + z \times (300)}{(w + x + y + z)}
\]

Where:

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

w = Percentage of total heat input derived from lignite;

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

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

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

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NOx does not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO2 emissions, NOx emissions, and either oxygen (O2 ) or carbon dioxide (CO2 ) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:
(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO2 emissions are not required if the owner or operator monitors SO2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO2 emissions is not required if the owner or operator monitors SO2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NOx may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NOx are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NOx emissions is not required. If the initial performance test results show that NOx emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NOx within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO2 or NOx, a CEMS for measuring either O2 or CO2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first
discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(7) An owner or operator of an affected facility subject to an opacity standard under § 60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section, shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (b)(7) of this section within 45 calendar days according to the requirements in § 60.46(b)(3).
(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO₂ and NOₓ continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in § 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NOₓ the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, SO₂ and NOₓ span values shall be determined as follows:

<table>
<thead>
<tr>
<th>Fossil fuel</th>
<th>In parts per million</th>
<th>Span value for SO₂</th>
<th>Span value for NOₓ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>(1)</td>
<td></td>
<td>500.</td>
</tr>
<tr>
<td>Liquid</td>
<td>1,000</td>
<td></td>
<td>500.</td>
</tr>
<tr>
<td>Solid</td>
<td>1,500</td>
<td></td>
<td>1,000.</td>
</tr>
<tr>
<td>Combinations</td>
<td>1,000y + 1,500z</td>
<td>500 (x + y) + 1,000z.</td>
<td></td>
</tr>
</tbody>
</table>

¹ Not applicable.

Where:

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

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

z = Fraction of total heat input derived from solid fossil fuel.
(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the SO$_2$ and NO$_x$ span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring O$_2$ is selected, the measurement of the pollutant concentration and O$_2$ concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

\[
E = CF \left( \frac{20.9}{20.9 - \%O_2} \right)
\]

Where $E$, $C$, $F$, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO$_2$ is selected, the measurement of the pollutant concentration and CO$_2$ concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

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

Where $E$, $C$, $F_c$ and $\%CO_2$ are determined under paragraph (f) of this section.

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

(1) $E$ = pollutant emissions, ng/J (lb/MMBtu).

(2) $C$ = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by $4.15 \times 10^4$ M ng/dscm per ppm (2.59 $\times 10^{-9}$ M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO$_2$ and 46.01 for NO$_x$.

(3) $\%O_2$, $\%CO_2$ = O$_2$ or CO$_2$ volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) $F$, $F_c$ = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted ($F$), and a factor representing a ratio of the volume of CO$_2$ generated to the calorific value of the fuel combusted ($F_c$), respectively. Values of $F$ and $F_c$ are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$ scm CO$_2$ /J (1,980 scf CO$_2$ /MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$ scm CO$_2$ /J (1,810 scf CO$_2$ /MMBtu).
(iii) For liquid fossil fuels including crude, residual, and distillate oils, \( F = 2.476 \times 10^{-7} \text{ dscm/J} \ (9.220 \text{ dscf/MMBtu}) \) and \( F_c = 0.384 \times 10^{-7} \text{ scm CO}_2 / J \ (1,430 \text{ scf CO}_2 / \text{MMBtu}) \).

(iv) For gaseous fossil fuels, \( F = 2.347 \times 10^{-7} \text{ dscm/J} \ (8.740 \text{ dscf/MMBtu}) \). For natural gas, propane, and butane fuels, \( F_c = 0.279 \times 10^{-7} \text{ scm CO}_2 / J \ (1,040 \text{ scf CO}_2 / \text{MMBtu}) \) for natural gas, \( 0.322 \times 10^{-7} \text{ scm CO}_2 / J \ (1,200 \text{ scf CO}_2 / \text{MMBtu}) \) for propane, and \( 0.338 \times 10^{-7} \text{ scm CO}_2 / J \ (1,260 \text{ scf CO}_2 / \text{MMBtu}) \) for butane.

(v) For bark \( F = 2.589 \times 10^{-7} \text{ dscm/J} \ (9.640 \text{ dscf/MMBtu}) \) and \( F_c = 0.500 \times 10^{-7} \text{ scm CO}_2 / J \ (1,840 \text{ scf CO}_2 / \text{MMBtu}) \). For wood residue other than bark \( F = 2.492 \times 10^{-7} \text{ dscm/J} \ (9.280 \text{ dscf/MMBtu}) \) and \( F_c = 0.494 \times 10^{-7} \text{ scm CO}_2 / J \ (1,860 \text{ scf CO}_2 / \text{MMBtu}) \).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), \( F = 2.659 \times 10^{-7} \text{ dscm/J} \ (9.900 \text{ dscf/MMBtu}) \) and \( F_c = 0.516 \times 10^{-7} \text{ scm CO}_2 / J \ (1,920 \text{ scf CO}_2 / \text{MMBtu}) \).

(5) The owner or operator may use the following equation to determine an \( F \) factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate \( F \) on a wet basis, consult the Administrator) or \( F_c \) factor (scm CO\(_2\) /J, or scf CO\(_2\) /MMBtu) on either basis in lieu of the \( F \) or \( F_c \) factors specified in paragraph (f)(4) of this section:

\[
F = 10^{-4} \left[ 227.2 \%H + 95.5 \%C + 33.6 \%S + 8.7 \%N - 28.7 \%O \right] / GCV
\]

\[
F_c = \frac{20 \times 10^{-3} \%C}{GCV} \text{ (SI units)}
\]

\[
F = 10^{-4} \left[ 3.64 \%H + 1.53 \%C + 0.57 \%S + 0.14 \%N - 0.46 \%O \right] / GCV \text{ (English units)}
\]

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

\[
F_c = \frac{321 \times 10^{-3} \%C}{GCV} \text{ (English units)}
\]

(i) \( \%H, \%C, \%S, \%N, \text{ and } \%O \) are content by weight of hydrogen, carbon, sulfur, nitrogen, and O\(_2\) (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see § 60.17.)

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see § 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the \( F \) or \( F_c \) value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the \( F \) or \( F_c \) factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

\[
F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i
\]
Where:

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

\[ F_i \text{ or } (F_c)_i = \text{Applicable } F \text{ or } F_c \text{ factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and} \]

\[ n = \text{Number of fuels being burned in combination.} \]

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

1. **Opacity**. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

   (i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

   (ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

2. **Sulfur dioxide**. Excess emissions for affected facilities are defined as:

   (i) For affected facilities electing not to comply with § 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO\(_2\) as measured by a CEMS exceed the applicable standard in § 60.43; or

   (ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO\(_2\) as measured by a CEMS exceed the applicable standard in § 60.43. Facilities complying with the 30-day SO\(_2\) standard shall use the most current associated SO\(_2\) compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.

3. **Nitrogen oxides**. Excess emissions for affected facilities using a CEMS for measuring NO\(_x\) are defined as:

   (i) For affected facilities electing not to comply with § 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in § 60.44; or

   (ii) For affected facilities electing to comply with § 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO\(_x\) as measured by a CEMS exceed the applicable standard in § 60.44. Facilities complying with the 30-day NO\(_x\) standard shall use the most current associated NO\(_x\) compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

4. **Particulate matter**. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in § 60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.
(h) The owner or operator of an affected facility subject to the opacity limits in § 60.42 that elects to monitor emissions according to the requirements in § 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO₂, and NOₓ standards in §§ 60.42, 60.43, and 60.44 as follows:

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

\[
E = CF \frac{20.9}{(20.9 - %O₂)}
\]

Where:

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

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

%O₂ = O₂ concentration, percent dry basis; and
$F_d =$ Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration ($C$) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration ($C$) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration (%$O_2$). The $O_2$ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the $O_2$ concentration for the run shall be the arithmetic mean of the sample $O_2$ concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the $O_2$ traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 $O_2$ traverse points.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the $SO_2$ concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration (%$O_2$). The $O_2$ sample shall be taken simultaneously with, and at the same point as, the $SO_2$ sample. The $SO_2$ emission rate shall be computed for each pair of $SO_2$ and $O_2$ samples. The $SO_2$ emission rate ($E$) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the $NO_x$ concentration.

(i) The sampling site and location shall be the same as for the $SO_2$ sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each $NO_x$ sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration (%$O_2$). The sample shall be taken simultaneously with, and at the same point as, the $NO_x$ sample.

(iii) The $NO_x$ emission rate shall be computed for each pair of $NO_x$ and $O_2$ samples. The $NO_x$ emission rate ($E$) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§ 60.43(b) and 60.44(b)) shall determine the percentage ($w$, $x$, $y$, or $z$) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see § 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.
(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate \( (E) \) of PM, \( \text{SO}_2 \) and \( \text{NO}_x \) may be determined by using the \( Fc \) factor, provided that the following procedure is used:

(i) The emission rate \( (E) \) shall be computed using the following equation:

\[
E = CE \left( \frac{100}{\%\text{CO}_2} \right)
\]

Where:

\( E = \text{Emission rate of pollutant, ng/J (lb/MMBtu)}; \)

\( C = \text{Concentration of pollutant, ng/dscm (lb/dscf)}; \)

\( \%\text{CO}_2 = \text{CO}_2 \text{ concentration, percent dry basis}; \) and

\( Fc = \text{Factor as determined in appropriate sections of Method 19 of appendix A of this part.} \)

(ii) If and only if the average \( Fc \) factor in Method 19 of appendix A of this part is used to calculate \( E \) and either \( E \) is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the \( O_2 \) and \( \text{CO}_2 \) concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if \( F_o \) (average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average \( F_o \) value, as determined from the average values of \( F_o \) and \( F_c \) in Method 19 of appendix A of this part, \( i.e. \), \( Foa = 0.209 \left( \frac{Fda}{Fc} \right) \), then the following procedure shall be followed:

(A) When \( F_o \) is less than 0.97 \( Foa \), then \( E \) shall be increased by that proportion under 0.97 \( Foa \), \( e.g. \), if \( F_o \) is 0.95 \( Foa \), \( E \) shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When \( F_o \) is less than 0.97 \( Foa \) and when the average difference \( (d) \) between the continuous monitor minus the reference methods is negative, then \( E \) shall be increased by that proportion under 0.97 \( Foa \), \( e.g. \), if \( F_o \) is 0.95 \( Foa \), \( E \) shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When \( F_o \) is greater than 1.03 \( Foa \) and when the average difference \( d \) is positive, then \( E \) shall be decreased by that proportion over 1.03 \( Foa \), \( e.g. \), if \( F_o \) is 1.05 \( Foa \), \( E \) shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A-3 of this part, Method 17 of appendix A-6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used with Method 17 of appendix A-6 of this part only if it is used after wet FGD systems. Method 17 of appendix A-6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and \( \text{SO}_2 \) may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:
(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO₂ (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO₂ emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O₂ concentration (%O₂) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Y—Standards of Performance for Coal Preparation and Processing Plants

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

(b) The provisions in § 60.251, § 60.252(a), § 60.253(a), § 60.254(a), § 60.255(a), and § 60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(c) The provisions in § 60.251, § 60.252(b)(1) and (c), § 60.253(b), § 60.254(b), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(d) The provisions in § 60.251, § 60.252(b)(1) through (3), and (c), § 60.253(b), § 60.254(b) and (c), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Clean Air Act (Act) and in subpart A of this part.

(a) Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

(b) Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

(c) Bituminous coal means solid fossil fuel classified as bituminous coal by ASTM D388 (incorporated by reference—see § 60.17).
(d) **Coal** means:

1. For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference—see §60.17).

2. For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference—see §60.17), and coal refuse.

(e) **Coal preparation and processing plant** means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(f) **Coal processing and conveying equipment** means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.

(g) **Coal refuse** means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

(h) **Coal storage system** means any facility used to store coal except for open storage piles.

(i) **Design controlled potential PM emissions rate** means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

(j) **Indirect thermal dryer** means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.

(k) **Lignite** means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

(l) **Mechanical vent** means any vent that uses a powered mechanical drive (machine) to induce air flow.

(m) **Open storage pile** means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.

(n) **Operating day** means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.

(o) **Pneumatic coal-cleaning equipment** means:

1. For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

2. For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).
(p) Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A-7 of this part.

(q) Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

(r) Thermal dryer means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.

(s) Transfer and loading system means any facility used to transfer and load coal for shipment.

§ 60.252   Standards for thermal dryers.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and

(2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide (SO2 ), and combined nitrogen oxides (NOX ) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

(1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).

(A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.

(ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.
(A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.

(2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for SO2 emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or

(ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain SO2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO2 in excess of 10 percent of the potential combustion concentration (i.e., the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an SO2 limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the SO2 limits of this section.

(3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined NOX and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of NOX and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.

(ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of NOX and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a NOX limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined NOX and CO limits of this section.

(c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

§ 60.253 Standards for pneumatic coal-cleaning equipment.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.
(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.023 g/dscm (0.010 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

(1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.

(2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).

(3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.

(c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.

(1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.

(2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met), use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.
(i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.

(ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).

(iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.

(iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.

(i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.

(ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.

(5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

§ 60.255 Performance tests and other compliance requirements.

(a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in § 60.257.
(b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of § 60.8 and the methods identified in § 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

(1) For each affected facility subject to a PM, SO\textsubscript{2}, or combined NO\textsubscript{x} and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.

(2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in § 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

(c) If any affected coal processing and conveying equipment (e.g., breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in § 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.

(d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.

(1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,

(2) The control device manufacturer's recommended maintenance procedures are followed, and

(3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.
(e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.

1. PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;

2. The manufacturer's recommended maintenance procedures are followed for each control device; and

3. A performance test is conducted on each affected facility at least once every 5 calendar years.

(f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.

1. Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

   i. Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in § 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of this part, performance test must be conducted within 45 operating days.

   ii. Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

   iii. Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

2. Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

(g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

1. The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

2. The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.
(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) The owner or operator must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(iii) The owner or operator must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(v) The owner or operator must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.

(1) Conduct an initial performance test using Method 9 of appendix A-4 of this part according to the requirements in paragraphs (h)(1)(i) and (ii).

(i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.

(ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.

(2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(3) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

§ 60.256 Continuous monitoring requirements.

(a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.

(1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(i) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(ii) For affected facilities that use wet scrubber emission control equipment:
(A) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(B) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator shall have discretion to grant requests for approval of alternative monitoring locations.

(2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).

(b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.

(1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.

(2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply flow rate.

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design pH.

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

(1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.
(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

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

(2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;
(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective fabric filter compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the PM emissions.

§ 60.257 Test methods and procedures.

(a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.

(1) Method 9 of appendix A-4 of this part and the procedures in § 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).

(i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages).

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

(2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

(3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.

(i) No more than three emissions points may be read concurrently.

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.

(b) The owner or operator must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emissions standards specified in § 60.252 according to the requirements in § 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.
(1) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses (incorporated by reference— see § 60.17) as an alternative to Method 3B of appendix A-2 of this part.

(4) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas.

(5) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows:

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test.

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications (e.g., stub stacks and roof vents).

(v) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(6) Method 6, 6A, or 6C of appendix A-4 of this part shall be used to determine the SO2 concentration. A minimum of three valid test runs are needed to comprise an SO2 performance test.

(7) Method 7 or 7E of appendix A-4 of this part shall be used to determine the NOX concentration. A minimum of three valid test runs are needed to comprise an NOX performance test.

(8) Method 10 of appendix A-4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with NOX performance tests.

§ 60.258 Reporting and recordkeeping.

(a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:

(1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.
(2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.

(3) The amount and type of coal processed each calendar month.

(4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.

(5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.

(6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, e.g. objections, to the plan and any actions relative to the alternative control measures, e.g. approvals, shall be noted in the logbook as well.

(7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.

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

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

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.

(8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.

(9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.

(10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.

(b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:

(1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.

(2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.

(3) All 6-minute average opacities that exceed the applicable standard.

(c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects
to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.

(d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main. For performance tests that cannot be entered into WebFIRE (i.e., Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711.
What This Subpart Covers

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.
(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).


§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE.

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) New stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) Reconstructed stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.
(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) Stationary RICE subject to limited requirements. (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;
(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.


§63.6595 When do I have to comply with this subpart?

(a) Affected sources. (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) Area sources that become major sources. If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.
(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.


Emission and Operating Limitations

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.


§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.
(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart III instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.


§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.
(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§63.6605  What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

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


Testing and Initial Compliance Requirements

§63.6610  By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.
(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.


§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.


§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.
§63.6620  What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

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

\[
\frac{C_i - C_o}{C_i} \times 100 = R \quad \text{(Eq. 1)}
\]

Where:

\( C_i \) = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

\( C_o \) = concentration of CO, THC, or formaldehyde at the control device outlet, and

\( R \) = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO2 concentration is measured in lieu of oxygen concentration measurement, a CO2 correction factor is needed. Calculate the CO2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

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

\[
F_o = \frac{0.209 \cdot F_d}{F_c} \quad \text{(Eq. 2)}
\]

Where:
F₀ = Fuel factor based on the ratio of oxygen volume to the ultimate CO₂ volume produced by the fuel at zero percent excess air.

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

Fₐ = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/100 Btu).

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

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

\[ X_{CO₂} = \frac{5.9}{F₀} \]  \hspace{1cm} (Eq. 3)

Where:

X_{CO₂} = CO₂ correction factor, percent.

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

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O₂ using CO₂ as follows:

\[ C_{adj} = C_d \frac{X_{CO₂}}{\%CO₂} \]  \hspace{1cm} (Eq. 4)

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O₂.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO₂} = CO₂ correction factor, percent.

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

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

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

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;
(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

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

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.


§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O₂ or CO₂ according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR
(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO₂ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

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

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.
(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combuts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.
(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.


§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.
(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O2 using one of the O2 measurement methods specified in Table 4 of this subpart. Measurements to determine O2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O2 emissions simultaneously at the inlet and outlet of the control device.


Continuous Compliance Requirements

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:
(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.
(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

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

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

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

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

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

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

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

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

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

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

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the
§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following:

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).
(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.


§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.
(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

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

(4) If you had a malfunction during the reporting period, the compliance report must include the 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 an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration 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, and whether each deviation occurred during a period of malfunction or during another period.

(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 breakdown 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 downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

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

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

(iii) Engine site rating and model year.

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

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).
(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

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

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


§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

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

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

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.
(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE:

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.


§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).


Other Requirements and Information

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a
site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with
the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new
stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on
an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§63.6670  Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or
tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that
agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your
U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40
CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of
the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under
§63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in
§63.6610(b).

§63.6675  What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this
part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to
Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric
Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and
the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment
associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to
the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions,
combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates
electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by
reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 et seq., as amended by Public Law 101-549, 104 Stat. 2399).
Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor’s offices, and sports and performing arts facilities.

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

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

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

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

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

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (e.g. biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

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

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).
(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

*Engine startup* means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

*Four-stroke engine* means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

*Gaseous fuel* means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

*Gasoline* means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

*Glycol dehydration unit* means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

*Hazardous air pollutants (HAP)* means any air pollutants listed in or pursuant to section 112(b) of the CAA.

*Institutional emergency stationary RICE* means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

*ISO standard day conditions* means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

*Landfill gas* means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

*Lean burn engine* means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

*Limited use stationary RICE* means any stationary RICE that operates less than 100 hours per year.

*Liquefied petroleum gas* means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

*Liquid fuel* means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

*Major Source*, as used in this subpart, shall have the same meaning as in §63.2, except that:

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

2. For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;
(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NOx) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NOx, CO, and volatile organic compounds (VOC) into CO2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8.
Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

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

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.
Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.


Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following emission limitation, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 4SRB stationary RICE</td>
<td>a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O₂</td>
<td>Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.¹</td>
</tr>
</tbody>
</table>

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following operating limitation, except during periods of startup . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O&lt;sub&gt;2&lt;/sub&gt; and using NSCR;</td>
<td>a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.¹</td>
</tr>
<tr>
<td>2. existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O&lt;sub&gt;2&lt;/sub&gt; and not using NSCR.</td>
<td>Comply with any operating limitations approved by the Administrator.</td>
</tr>
</tbody>
</table>

¹Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following emission limitation, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 2SLB stationary RICE</td>
<td>a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O&lt;sub&gt;2&lt;/sub&gt;. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O&lt;sub&gt;2&lt;/sub&gt; until June 15, 2007</td>
<td>Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.¹</td>
</tr>
<tr>
<td>2. 4SLB stationary RICE</td>
<td>a. Reduce CO emissions by 93 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O&lt;sub&gt;2&lt;/sub&gt;</td>
<td></td>
</tr>
</tbody>
</table>
For each . . . | You must meet the following emission limitation, except during periods of startup . . . | During periods of startup you must . . .
--- | --- | ---
3. CI stationary RICE | a. Reduce CO emissions by 70 percent or more; or | b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O₂

1Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following operating limitation, except during periods of startup . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New and reconstructed 2SLB and CI stationary RICE &gt;500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.</td>
<td>a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹</td>
</tr>
</tbody>
</table>

| 2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst | a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹ |

| 3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and | Comply with any operating limitations approved by the Administrator. |
For each . . . | You must meet the following operating limitation, except during periods of startup . . .
---|---
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.

1Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

| For each . . . | You must meet the following requirement, except during periods of startup . . . | During periods of startup you must . . . |
---|---|---
1. Emergency stationary CI RICE and black start stationary CI RICE¹ | a. Change oil and filter every 500 hours of operation or annually, whichever comes first.²  
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;  
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³ | Minimize the engine’s time spent at idle and minimize the engine’s startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.³ |

2. Non-Emergency, non-black start stationary CI RICE <100 HP | a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.²  
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;  
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³ |  |

3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP | Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O₂.
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>4. Non-Emergency, non-black start CI stationary RICE 300&lt;HP≤500</td>
<td>a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more.</td>
<td></td>
</tr>
<tr>
<td>5. Non-Emergency, non-black start stationary CI RICE &gt;500 HP</td>
<td>a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more.</td>
<td></td>
</tr>
<tr>
<td>6. Emergency stationary SI RICE and black start stationary SI RICE.¹</td>
<td>a. Change oil and filter every 500 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
<tr>
<td>7. Non-Emergency, non-black start stationary SI RICE &lt;100 HP that are not 2SLB stationary RICE</td>
<td>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
<tr>
<td>8. Non-Emergency, non-black start 2SLB stationary SI RICE &lt;100 HP</td>
<td>a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
<tr>
<td>For each . . .</td>
<td>You must meet the following requirement, except during periods of startup . . .</td>
<td>During periods of startup you must . . .</td>
</tr>
<tr>
<td>---------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500</td>
<td>Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O$_2$.</td>
<td></td>
</tr>
<tr>
<td>10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500</td>
<td>Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O$_2$.</td>
<td></td>
</tr>
<tr>
<td>11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500</td>
<td>Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O$_2$.</td>
<td></td>
</tr>
<tr>
<td>12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis</td>
<td>Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O$_2$.</td>
<td></td>
</tr>
</tbody>
</table>

1If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

2Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

3Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]
Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
</table>
| 1. Non-Emergency, non-black start CI stationary RICE ≤300 HP | a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; \(^1\)  
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;  
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. | Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. |
| 2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500 | a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O\(_2\); or  
b. Reduce CO emissions by 70 percent or more. |  |
| 3. Non-Emergency, non-black start CI stationary RICE >500 HP | a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O\(_2\); or  
b. Reduce CO emissions by 70 percent or more. |  |
| 4. Emergency stationary CI RICE and black start stationary CI RICE.\(^2\) | a. Change oil and filter every 500 hours of operation or annually, whichever comes first; \(^1\)  
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and  
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. |  |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
</table>
| 5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE \(>500\) HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE \(>500\) HP that operate 24 hours or less per calendar year.\(^2\) | a. Change oil and filter every 500 hours of operation or annually, whichever comes first;\(^1\)  
    b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and  
    c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. |  |
| 6. Non-emergency, non-black start 2SLB stationary RICE | a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;\(^1\)  
    b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and  
    c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. |  |
| 7. Non-emergency, non-black start 4SLB stationary RICE \(\leq 500\) HP | a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;\(^1\)  
    b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and  
    c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. |  |
| 8. Non-emergency, non-black start 4SLB remote stationary RICE \(>500\) HP | a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;\(^1\)  
    b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and |  |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
</table>

| 9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year | Install an oxidation catalyst to reduce HAP emissions from the stationary RICE. | c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary. |

| 10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP | a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹ | b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and |
| | | c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. |

| 11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP | a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;¹ | b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and |
| | | c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary. |

| 12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year | Install NSCR to reduce HAP emissions from the stationary RICE. | b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and |
| | | c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary. |

| 13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis | a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹ | b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and |
For each . . .  | You must meet the following requirement, except during periods of startup . . .  | During periods of startup you must . . .
---|---|---
c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.

1Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

2If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

**Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests**

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New or reconstructed 2SLB stationary RICE &gt;500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE &gt;500 HP located at major sources</td>
<td>Reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests semiannually.1</td>
</tr>
<tr>
<td>2. 4SRB stationary RICE ≥5,000 HP located at major sources</td>
<td>Reduce formaldehyde emissions</td>
<td>Conduct subsequent performance tests semiannually.1</td>
</tr>
<tr>
<td>3. Stationary RICE &gt;500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources</td>
<td>Limit the concentration of formaldehyde in the stationary RICE exhaust</td>
<td>Conduct subsequent performance tests semiannually.1</td>
</tr>
<tr>
<td>4. Existing non-emergency, non-black start CI stationary RICE &gt;500 HP that are not limited use stationary RICE</td>
<td>Limit or reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.</td>
</tr>
<tr>
<td>5. Existing non-emergency, non-black start CI stationary RICE &gt;500 HP that are limited use stationary RICE</td>
<td>Limit or reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.</td>
</tr>
</tbody>
</table>

1After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]
Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

<table>
<thead>
<tr>
<th>For each</th>
<th>Complying with the requirement to</th>
<th>You must . . .</th>
<th>Using . . .</th>
<th>According to the following requirements . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 2SLB, 4SLB, and CI stationary RICE</td>
<td>a. reduce CO emissions</td>
<td>i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and</td>
<td>(a) For CO and O₂ measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (‘3-point long line’). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at ‘3-point long line’; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(b) Measurements to determine O₂ must be made at the same time as the measurements for CO concentration.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Measure the O₂ at the inlet and outlet of the control device; and</td>
<td>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)ac (heated probe not necessary)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(c) The CO concentration must be at 15 percent O₂, dry basis.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Measure the CO at the inlet and the outlet of the control device</td>
<td>(1) ASTM D6522-00 (Reapproved 2005)abc (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4</td>
<td></td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must . . .</td>
<td>Using . . .</td>
<td>According to the following requirements . . .</td>
</tr>
<tr>
<td>---------------</td>
<td>----------------------------------------</td>
<td>----------------</td>
<td>-------------</td>
<td>-----------------------------------------------</td>
</tr>
<tr>
<td>2. 4SRB stationary RICE</td>
<td>a. reduce formaldehyde emissions</td>
<td>i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and</td>
<td>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)a (heated probe not necessary)</td>
<td>(a) For formaldehyde, $O_2$, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (‘3-point long line’). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at ‘3-point long line’; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Measure $O_2$ at the inlet and outlet of the control device; and</td>
<td></td>
<td>(a) Measurements to determine $O_2$ concentration must be made at the same time as the measurements for formaldehyde or THC concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Measure moisture content at the inlet and outlet of the control device; and</td>
<td>(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03a</td>
<td>(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device</td>
<td>(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03a, provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130</td>
<td>(a) Formaldehyde concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device</td>
<td>(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7</td>
<td>(a) THC concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must . . .</td>
<td>Using . . .</td>
<td>According to the following requirements . . .</td>
</tr>
<tr>
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<td>-------------</td>
<td>-----------------------------------------------</td>
</tr>
<tr>
<td>3. Stationary RICE</td>
<td>a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust</td>
<td>i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and</td>
<td>(a) For formaldehyde, CO, O₂, and moisture measurement, ducts ( \leq 6 ) inches in diameter may be sampled at a single point located at the duct centroid and ducts ( &gt; 6 ) and ( \leq 12 ) inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (&quot;3-point long line&quot;). If the duct is ( &gt; 12 ) inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Determine the O₂ concentration of the stationary RICE exhaust at the sampling port location; and</td>
<td>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)\textsuperscript{a} (heated probe not necessary)</td>
<td>(a) Measurements to determine O₂ concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and</td>
<td>(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03\textsuperscript{a}</td>
<td>(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Measure formaldehyde at the exhaust of the stationary RICE; or</td>
<td>(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03\textsuperscript{a}, provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent ( R ) must be greater than or equal to 70 and less than or equal to 130</td>
<td>(a) Formaldehyde concentration must be at 15% O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td></td>
<td>v. measure CO at the exhaust of the stationary RICE</td>
<td></td>
<td>(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)\textsuperscript{c}, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03\textsuperscript{a}</td>
<td>(a) CO concentration must be at 15% O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
</tbody>
</table>
You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

**Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements**

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You have demonstrated initial compliance if . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Reduce CO emissions and using oxidation catalyst, and using a CPMS</td>
<td>i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.</td>
</tr>
<tr>
<td>2. Non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS</td>
<td>i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.</td>
</tr>
<tr>
<td>3. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Reduce CO emissions and not using oxidation catalyst</td>
<td>i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You have demonstrated initial compliance if . . .</td>
</tr>
<tr>
<td>----------------</td>
<td>----------------------------------------</td>
<td>---------------------------------------------------</td>
</tr>
<tr>
<td>4. Non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Limit the concentration of CO, and not using oxidation catalyst</td>
<td>i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.</td>
</tr>
<tr>
<td>5. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Reduce CO emissions, and using a CEMS</td>
<td>i. You have installed a CEMS to continuously monitor CO and either O₂ or CO₂ at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.</td>
</tr>
<tr>
<td>6. Non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Limit the concentration of CO, and using a CEMS</td>
<td>i. You have installed a CEMS to continuously monitor CO and either O₂ or CO₂ at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.</td>
</tr>
<tr>
<td>7. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions and using NSCR</td>
<td>i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You have demonstrated initial compliance if . . .</td>
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</tr>
<tr>
<td></td>
<td>ii. You have installed a CPMS to</td>
<td>i. The average reduction of emissions of</td>
</tr>
<tr>
<td></td>
<td>continuously monitor catalyst inlet</td>
<td>formaldehyde determined from the initial</td>
</tr>
<tr>
<td></td>
<td>temperature according to the requirements</td>
<td>performance test is equal to or greater than</td>
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<tr>
<td></td>
<td>in §63.6625(b); and</td>
<td>the required formaldehyde percent</td>
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<tr>
<td></td>
<td>iii. You have recorded the catalyst</td>
<td>reduction or the average reduction of</td>
</tr>
<tr>
<td></td>
<td>pressure drop and catalyst inlet</td>
<td>emissions of THC determined from the initial</td>
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<tr>
<td></td>
<td>temperature during the initial</td>
<td>performance test is equal to or greater than</td>
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<tr>
<td></td>
<td>performance test.</td>
<td>30 percent; and</td>
</tr>
<tr>
<td>8. Non-emergency 4SRB stationary RICE</td>
<td>a. Reduce formaldehyde emissions and not</td>
<td>ii. You have installed a CPMS to</td>
</tr>
<tr>
<td>&gt;500 HP located</td>
<td>using NSCR</td>
<td>continuously monitor operating parameters</td>
</tr>
<tr>
<td>at a major source of HAP</td>
<td></td>
<td>approved by the Administrator (if any)</td>
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<tr>
<td></td>
<td></td>
<td>according to the requirements in §63.6625(b);</td>
</tr>
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<td></td>
<td></td>
<td>and</td>
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<td></td>
<td></td>
<td>ii. You have recorded the approved</td>
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<td></td>
<td></td>
<td>operating parameters (if any) during the initial</td>
</tr>
<tr>
<td></td>
<td></td>
<td>performance test.</td>
</tr>
<tr>
<td>9. New or reconstructed non-emergency</td>
<td>a. Limit the concentration of</td>
<td>i. The average formaldehyde concentration,</td>
</tr>
<tr>
<td>stationary RICE</td>
<td>formaldehyde in the stationary RICE</td>
<td>corrected to 15 percent O₂, dry basis, from the</td>
</tr>
<tr>
<td>&gt;500 HP located</td>
<td>exhaust and using oxidation catalyst or NSCR</td>
<td>three test runs is less than or equal to the</td>
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<tr>
<td>at a major source of HAP</td>
<td></td>
<td>formaldehyde emission limitation; and</td>
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<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to</td>
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<tr>
<td></td>
<td></td>
<td>continuously monitor catalyst inlet</td>
</tr>
<tr>
<td></td>
<td></td>
<td>temperature according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>pressure drop and catalyst inlet</td>
</tr>
<tr>
<td></td>
<td></td>
<td>temperature during the initial performance test.</td>
</tr>
<tr>
<td>10. New or reconstructed non-emergency</td>
<td>a. Limit the concentration of</td>
<td>i. The average formaldehyde concentration,</td>
</tr>
<tr>
<td>stationary RICE</td>
<td>formaldehyde in the stationary RICE</td>
<td>corrected to 15 percent O₂, dry basis, from the</td>
</tr>
<tr>
<td>&gt;500 HP located</td>
<td>exhaust and not using NSCR</td>
<td>three test runs is less than or equal to the</td>
</tr>
<tr>
<td>at a major source of HAP</td>
<td></td>
<td>formaldehyde emission limitation; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to</td>
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<td></td>
<td></td>
<td>continuously monitor operating parameters</td>
</tr>
<tr>
<td></td>
<td></td>
<td>approved by the Administrator (if any) according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the approved</td>
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<tr>
<td></td>
<td></td>
<td>operating parameters (if any) during the initial</td>
</tr>
<tr>
<td></td>
<td></td>
<td>performance test.</td>
</tr>
<tr>
<td>11. Existing non-emergency stationary RICE</td>
<td>a. Reduce CO emissions</td>
<td>i. The average reduction of emissions of CO or</td>
</tr>
<tr>
<td>100≤HP≤500 located</td>
<td></td>
<td>formaldehyde, as applicable determined from the</td>
</tr>
<tr>
<td>at a major source of HAP</td>
<td></td>
<td>initial performance test is equal to or greater</td>
</tr>
<tr>
<td></td>
<td></td>
<td>than the required CO or formaldehyde, as</td>
</tr>
<tr>
<td></td>
<td></td>
<td>applicable, percent reduction.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You have demonstrated initial compliance if . . .</td>
</tr>
<tr>
<td>---------------</td>
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<td>-----------------------------------------------</td>
</tr>
<tr>
<td>12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP and existing non-emergency stationary CI RICE 300&lt;HP≤500 located at an area source of HAP</td>
<td>a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust</td>
<td>i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.</td>
</tr>
<tr>
<td>13. Existing non-emergency 4SLB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install an oxidation catalyst</td>
<td>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.</td>
</tr>
<tr>
<td>14. Existing non-emergency 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install NSCR</td>
<td>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.</td>
</tr>
</tbody>
</table>

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS</td>
<td>i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
</tr>
<tr>
<td>---------------</td>
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<td>--------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</td>
<td></td>
</tr>
<tr>
<td>2. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE &gt;500 HP located at a major source of HAP</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS</td>
<td>i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td>3. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS</td>
<td>i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and</td>
</tr>
<tr>
<td>4. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. Reduce formaldehyde emissions and using NSCR</td>
<td>i. Collecting the catalyst inlet temperature data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
</tr>
<tr>
<td>----------------</td>
<td>------------------------------------------</td>
<td>-----------------------------------------------</td>
</tr>
<tr>
<td>5. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions and not using NSCR</td>
<td>i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
<tr>
<td>6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions</td>
<td>Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.a</td>
</tr>
<tr>
<td>7. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR</td>
<td>i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</td>
</tr>
<tr>
<td>8. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR</td>
<td>i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
</tr>
<tr>
<td>------------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>9. Existing emergency and black start stationary RICE ≤500 HP located at a</td>
<td>a. Work or Management practices</td>
<td>i. Operating and maintaining the stationary RICE according to the manufacturer’s emission-related operation and maintenance instructions; or</td>
</tr>
<tr>
<td>major source of HAP, existing non-emergency stationary RICE ≤100 HP located</td>
<td>i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as</td>
<td>ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.</td>
</tr>
<tr>
<td>at a major source of HAP, existing emergency and black start stationary</td>
<td>appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved</td>
<td></td>
</tr>
<tr>
<td>RICE located at an area source of HAP, existing non-emergency stationary</td>
<td>or that your emissions remain at or below the CO or formaldehyde concentration limit; and</td>
<td></td>
</tr>
<tr>
<td>CI RICE ≤300 HP located at an area source of HAP, existing non-emergency</td>
<td>i. Collecting the catalyst inlet temperature data according to §63.6625(b); and</td>
<td></td>
</tr>
<tr>
<td>2SLB stationary RICE located at an area source of HAP, existing non-emergency</td>
<td>ii. Reducing these data to 4-hour rolling averages; and</td>
<td></td>
</tr>
<tr>
<td>emergency stationary SI RICE located at an area source of HAP which</td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature;</td>
<td></td>
</tr>
<tr>
<td>combusts landfill or digester gas equivalent to 10 percent or more of the</td>
<td>v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop</td>
<td></td>
</tr>
<tr>
<td>gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB</td>
<td>across the catalyst is within the operating limitation established during the performance test.</td>
<td></td>
</tr>
<tr>
<td>stationary RICE ≤500 HP located at an area source of HAP, existing non-</td>
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<tr>
<td>emergency 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of</td>
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<tr>
<td>HAP that operate 24 hours or less per calendar year, and existing non-</td>
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<tr>
<td>emergency 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of</td>
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<tr>
<td>HAP that are remote stationary RICE</td>
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<tr>
<td>10. Existing stationary CI RICE &gt;500 HP that are not limited use stationary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RICE</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Reduce CO emissions, or limit the concentration of CO in the stationary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RICE exhaust, and using oxidation catalyst</td>
<td></td>
<td></td>
</tr>
<tr>
<td>i. Conducting performance tests every 8,760 hours or 3 years, whichever</td>
<td></td>
<td></td>
</tr>
<tr>
<td>comes first, for CO or formaldehyde, as appropriate, to demonstrate that</td>
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<td></td>
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<tr>
<td>the required CO or formaldehyde, as appropriate, percent reduction is</td>
<td></td>
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<tr>
<td>achieved or that your emissions remain at or below the CO or formaldehyde</td>
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<td></td>
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<tr>
<td>concentration limit; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ii. Collecting the approved operating parameter (if any) data according to</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6625(b); and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11. Existing stationary CI RICE &gt;500 HP that are not limited use stationary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RICE</td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Reduce CO emissions, or limit the concentration of CO in the stationary</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RICE exhaust, and not using oxidation catalyst</td>
<td></td>
<td></td>
</tr>
<tr>
<td>i. Conducting performance tests every 8,760 hours or 3 years, whichever</td>
<td></td>
<td></td>
</tr>
<tr>
<td>comes first, for CO or formaldehyde, as appropriate, to demonstrate that</td>
<td></td>
<td></td>
</tr>
<tr>
<td>the required CO or formaldehyde, as appropriate, percent reduction is</td>
<td></td>
<td></td>
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<tr>
<td>achieved or that your emissions remain at or below the CO or formaldehyde</td>
<td></td>
<td></td>
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<tr>
<td>concentration limit; and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ii. Collecting the approved operating parameter (if any) data according to</td>
<td></td>
<td></td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
</tr>
<tr>
<td>---------------</td>
<td>----------------------------------------</td>
<td>-----------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
</tbody>
</table>
| 12. Existing limited use CI stationary RICE >500 HP | a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst  

i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and  

ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and  

iii. Reducing these data to 4-hour rolling averages; and  

iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and  

v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
|               |                                        | ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and  

iii. Reducing these data to 4-hour rolling averages; and  

iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |
| 13. Existing limited use CI stationary RICE >500 HP | a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst  

i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and  

ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and  

iii. Reducing these data to 4-hour rolling averages; and  

iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>14. Existing non-emergency 4SLB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install an oxidation catalyst</td>
<td>i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O₂; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.</td>
</tr>
<tr>
<td>15. Existing non-emergency 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install NSCR</td>
<td>i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O₂; or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.</td>
</tr>
</tbody>
</table>

*aAfter you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]
Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must submit a . . .</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Existing non-emergency, non-black start stationary RICE 100s≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE &gt;500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP; and new or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>Compliance report</td>
<td>a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or</td>
<td>i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).</td>
<td>i. Semiannually according to the requirements in §63.6650(b).</td>
</tr>
<tr>
<td>2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis</td>
<td>Report</td>
<td>a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and</td>
<td>i. Annually, according to the requirements in §63.6650.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and</td>
<td>i. See item 2.a.i.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Any problems or errors suspected with the meters.</td>
<td>i. See item 2.a.i.</td>
</tr>
<tr>
<td>3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year</td>
<td>Compliance report</td>
<td>a. The results of the annual compliance demonstration, if conducted during the reporting period.</td>
<td>i. Semiannually according to the requirements in §63.6650(b)(1)-(5).</td>
</tr>
</tbody>
</table>
For each . . . | You must submit a . . . | The report must contain . . . | You must submit the report . . .
---|---|---|---
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii) | Report | a. The information in §63.6650(h)(1) i. annually according to the requirements in §63.6650(h)(2)-(3). |

[78 FR 6719, Jan. 30, 2013]

**Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.**

As stated in §63.6665, you must comply with the following applicable general provisions.

<table>
<thead>
<tr>
<th>General provisions citation</th>
<th>Subject of citation</th>
<th>Applies to subpart</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>General applicability of the General Provisions</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes</td>
<td>Additional terms defined in §63.6675.</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and abbreviations</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited activities and circumvention</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.5</td>
<td>Construction and reconstruction</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(a)</td>
<td>Applicability</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(1)-(4)</td>
<td>Compliance dates for new and reconstructed sources</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(5)</td>
<td>Notification</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(6)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(7)</td>
<td>Compliance dates for new and reconstructed area sources that become major sources</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(1)-(2)</td>
<td>Compliance dates for existing sources</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(3)-(4)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(5)</td>
<td>Compliance dates for existing area sources that become major sources</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(d)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(e)</td>
<td>Operation and maintenance</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>Applicability of standards</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(2)</td>
<td>Methods for determining compliance</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(3)</td>
<td>Finding of compliance</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(g)(1)-(3)</td>
<td>Use of alternate standard</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.6(h)</td>
<td>Opacity and visible emission standards</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or visible emission standards.</td>
</tr>
<tr>
<td>§63.6(i)</td>
<td>Compliance extension procedures and criteria</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>General provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
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</tr>
<tr>
<td>§63.6(j)</td>
<td>Presidential compliance exemption</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(a)(1)-(2)</td>
<td>Performance test dates</td>
<td>Yes</td>
<td>Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.</td>
</tr>
<tr>
<td>§63.7(a)(3)</td>
<td>CAA section 114 authority</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(b)(1)</td>
<td>Notification of performance test</td>
<td>Yes.</td>
<td>Except that §63.7(b)(1) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(b)(2)</td>
<td>Notification of rescheduling</td>
<td>Yes.</td>
<td>Except that §63.7(b)(2) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(c)</td>
<td>Quality assurance/test plan</td>
<td>Yes.</td>
<td>Except that §63.7(c) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(d)</td>
<td>Testing facilities</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Conditions for conducting performance tests</td>
<td>No.</td>
<td>Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.</td>
</tr>
<tr>
<td>§63.7(e)(2)</td>
<td>Conduct of performance tests and reduction of data</td>
<td>Yes.</td>
<td>Subpart ZZZZ specifies test methods at §63.6620.</td>
</tr>
<tr>
<td>§63.7(e)(3)</td>
<td>Test run duration</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(e)(4)</td>
<td>Administrator may require other testing under section 114 of the CAA</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(f)</td>
<td>Alternative test method provisions</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(g)</td>
<td>Performance test data analysis, recordkeeping, and reporting</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.7(h)</td>
<td>Waiver of tests</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(a)(1)</td>
<td>Applicability of monitoring requirements</td>
<td>Yes</td>
<td>Subpart ZZZZ contains specific requirements for monitoring at §63.6625.</td>
</tr>
<tr>
<td>§63.8(a)(2)</td>
<td>Performance specifications</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(a)(3)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.8(a)(4)</td>
<td>Monitoring for control devices</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.8(b)(1)</td>
<td>Monitoring</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(b)(2)-(3)</td>
<td>Multiple effluents and multiple monitoring systems</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)</td>
<td>Monitoring system operation and maintenance</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>Routine and predictable SSM</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(ii)</td>
<td>SSM not in Startup Shutdown Malfunction Plan</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Compliance with operation and maintenance requirements</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(2)-(3)</td>
<td>Monitoring system installation</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(4)</td>
<td>Continuous monitoring system (CMS) requirements</td>
<td>Yes</td>
<td>Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).</td>
</tr>
<tr>
<td>§63.8(c)(5)</td>
<td>COMS minimum procedures</td>
<td>No</td>
<td>Subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>§63.8(c)(6)-(8)</td>
<td>CMS requirements</td>
<td>Yes.</td>
<td>Except that subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>General provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
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<tr>
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</tr>
<tr>
<td>§63.8(d)</td>
<td>CMS quality control</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(e)</td>
<td>CMS performance evaluation</td>
<td>Yes</td>
<td>Except for §63.8(e)(5)(ii), which applies to COMS.</td>
</tr>
<tr>
<td>§63.8(f)(1)-(5)</td>
<td>Alternative monitoring method</td>
<td>Yes</td>
<td>Except that §63.8(f)(4) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.8(f)(6)</td>
<td>Alternative to relative accuracy test</td>
<td>Yes</td>
<td>Except that §63.8(f)(6) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.8(g)</td>
<td>Data reduction</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.9(a)</td>
<td>Applicability and State delegation of notification requirements</td>
<td>Yes.</td>
<td>Except that §63.9(b)(3) is reserved.</td>
</tr>
<tr>
<td>§63.9(b)(1)-(5)</td>
<td>Initial notifications</td>
<td>Yes</td>
<td>Except that §63.9(b)(3) is reserved.</td>
</tr>
<tr>
<td>§63.9(c)</td>
<td>Request for compliance extension</td>
<td>Yes</td>
<td>Except that §63.9(c) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(d)</td>
<td>Notification of special compliance requirements for new sources</td>
<td>Yes</td>
<td>Except that §63.9(d) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(e)</td>
<td>Notification of performance test</td>
<td>Yes</td>
<td>Except that §63.9(e) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.9(f)</td>
<td>Notification of visible emission (VE)/opacity test</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
</tr>
<tr>
<td>§63.9(g)(1)</td>
<td>Notification of performance evaluation</td>
<td>Yes</td>
<td>Except that §63.9(g) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(g)(2)</td>
<td>Notification of use of COMS data</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
</tr>
<tr>
<td>§63.9(g)(3)</td>
<td>Notification that criterion for alternative to RATA is exceeded</td>
<td>Yes</td>
<td>If alternative is in use.</td>
</tr>
<tr>
<td>§63.9(h)(1)-(6)</td>
<td>Notification of compliance status</td>
<td>Yes</td>
<td>Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.</td>
</tr>
<tr>
<td>§63.9(i)</td>
<td>Adjustment of submittal deadlines</td>
<td>Yes.</td>
<td>Except that §63.9(h) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.9(j)</td>
<td>Change in previous information</td>
<td>Yes.</td>
<td>Except that §63.9(h) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>General provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
</tr>
<tr>
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<td>--------------------------------------------------------</td>
<td>--------------------</td>
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<tr>
<td>§63.10(a)</td>
<td>Administrative provisions for recordkeeping/reporting</td>
<td>Yes.</td>
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<tr>
<td>§63.10(b)(1)</td>
<td>Record retention</td>
<td>Yes</td>
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<tr>
<td>§63.10(b)(2)(i)-(v)</td>
<td>Records related to SSM</td>
<td>No.</td>
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<tr>
<td>§63.10(b)(2)(vi)-(xi)</td>
<td>Records when under waiver</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.10(b)(2)(xii)</td>
<td>Records when using alternative to RATA</td>
<td>Yes.</td>
<td>For CO standard if using RATA alternative.</td>
</tr>
<tr>
<td>§63.10(b)(2)(xiii)</td>
<td>Records of supporting documentation</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.10(b)(2)(xiv)</td>
<td>Records of applicability determination</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.10(c)</td>
<td>Additional records for sources using CEMS</td>
<td>Yes.</td>
<td>Except that §63.10(c)(2)-(4) and (9) are reserved.</td>
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<tr>
<td>§63.10(d)(1)</td>
<td>General reporting requirements</td>
<td>Yes.</td>
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<tr>
<td>§63.10(d)(2)</td>
<td>Report of performance test results</td>
<td>Yes.</td>
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<tr>
<td>§63.10(d)(3)</td>
<td>Reporting opacity or VE observations</td>
<td>No.</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
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<tr>
<td>§63.10(d)(4)</td>
<td>Progress reports</td>
<td>Yes.</td>
<td></td>
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<td>§63.10(d)(5)</td>
<td>Startup, shutdown, and malfunction reports</td>
<td>No.</td>
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<td>§63.10(e)(1) and (2)(i)</td>
<td>Additional CMS Reports</td>
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<td>§63.10(e)(2)(ii)</td>
<td>COMS-related report</td>
<td>No.</td>
<td>Subpart ZZZZ does not require COMS.</td>
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<tr>
<td>§63.10(e)(3)</td>
<td>Excess emission and parameter exceedances reports</td>
<td>Yes.</td>
<td>Except that §63.10(e)(3)(i) (C) is reserved.</td>
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<tr>
<td>§63.10(e)(4)</td>
<td>Reporting COMS data</td>
<td>No.</td>
<td>Subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>§63.10(f)</td>
<td>Waiver for recordkeeping/reporting</td>
<td>Yes.</td>
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</tr>
<tr>
<td>§63.11</td>
<td>Flares</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.12</td>
<td>State authority and delegations</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.13</td>
<td>Addresses</td>
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<td>§63.14</td>
<td>Incorporation by reference</td>
<td>Yes.</td>
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<tr>
<td>§63.15</td>
<td>Availability of information</td>
<td>Yes.</td>
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</tbody>
</table>

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

<table>
<thead>
<tr>
<th>Analyte</th>
<th>CAS No.</th>
<th>Sensitivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon monoxide (CO)</td>
<td>630-08-0</td>
<td>Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.</td>
</tr>
<tr>
<td>Oxygen (O_2)</td>
<td>7782-44-7</td>
<td></td>
</tr>
</tbody>
</table>

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:
3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O₂ and moisture in the electrolyte reserve and provides a mechanism to degas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre-sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.
3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO₂ are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O₂ concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O₂; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.
6.2.12 **Interference Gas Filter or Scrubber.** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 **Reagents and Standards.** What calibration gases are needed?

7.1 **Calibration Gases.** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O₂. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O₂) is acceptable for calibration of the O₂ cell. If needed, any lower percentage O₂ calibration gas must be a mixture of O₂ in nitrogen.

7.1.1 **Up-Scale CO Calibration Gas Concentration.** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 **Up-Scale O₂ Calibration Gas Concentration.**

Select an O₂ gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O₂. When the average exhaust gas O₂ readings are above 6 percent, you may use dry ambient air (20.9 percent O₂) for the up-scale O₂ calibration gas.

7.1.3 **Zero Gas.** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO₂).

8.0 **Sample Collection and Analysis**

8.1 **Selection of Sampling Sites.**

8.1.1 **Control Device Inlet.** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 **Exhaust Gas Outlet.** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 **Stack Gas Collection and Analysis.** Prior to the first stack gas sampling run, conduct the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O₂ concentrations.

8.3 **EC Cell Rate.** Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 **Quality Control (Reserved)**
10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O₂ and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O₂ for the O₂ channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O₂, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O₂, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O₂ concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm,
whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must
conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean
is greater than ±2 percent or ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of
below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-
annually thereafter, challenge the interference gas scrubber with NO and NO2 gas standards that are generally
recognized as representative of diesel-fueled engine NO and NO2 emission values. Record the responses displayed
by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO2 interference response should be less than or equal to ±5
percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC
cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat
this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas
concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the
CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to
record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs,
do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO
concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The
absolute value of the difference between the maximum and minimum average values recorded must not vary more
than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) "Development of an Electrochemical Cell Emission Analyzer Test Protocol", Topical Report, Phil Juneau,

(2) "Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines,
Boilers, and Process Heaters Using Portable Analyzers", EMC Conditional Test Protocol 30 (CTM-30), Gas Research

(3) "ICAC Test Protocol for Periodic Monitoring", EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean
Air Companies, September 8, 1999.

Table 1: Appendix A—Sampling Run Data.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Engine I.D.</th>
<th>Date</th>
</tr>
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<tbody>
<tr>
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</tbody>
</table>

Run Type: Pre-Sample Calibration, Stack Gas Sample, Post-Sample Cal. Check, Repeatability Check

<table>
<thead>
<tr>
<th>Run #</th>
<th>Time</th>
<th>Scrub. OK</th>
<th>Flow- Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
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<td></td>
</tr>
<tr>
<td>4</td>
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</table>

Gas: O₂, CO

Sample Cond. Phase

Measurement Data Phase

Mean

Refresh Phase

[78 FR 6721, Jan. 30, 2013]
Attachment D

Part 70 Operating Permit No: 147-40656-00020

Title 40: Protection of Environment

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

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

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

What This Subpart Covers

§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

[78 FR 7162, Jan. 31, 2013]

§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.
(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.


§63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.
(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(i) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for an exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.


Emission Limitations and Work Practice Standards

§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.
(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 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, co-generate 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 (co-generation 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.
(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).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

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

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 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.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.


§63.7501  [Reserved]

General Compliance Requirements

§63.7505  What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(b) [Reserved]
(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), 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.

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

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

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

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

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

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

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

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

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.

(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.

(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.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495,
except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. 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.

(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 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.

(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.


§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 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.

(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).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in 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.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than 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.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) 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).


§63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process...
heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 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]

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

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 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.


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

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 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.

\[
\text{AveWeightedEmissions} = \frac{1.1 \times \sum_{i=1}^{n} (E_r \times H_m) + n \times H_m}{n \times H_m} \quad \text{(Eq. 1a)}
\]

Where:

\(\text{AveWeightedEmissions} = \text{Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.}\)

\(E_r = \text{Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).}\)

\(H_m = \text{Maximum rated heat input capacity of unit, i, in units of million Btu per hour.}\)

\(n = \text{Number of units participating in the emissions averaging option.}\)

\(1.1 = \text{Required discount factor.}\)
Where:

\[ \text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^{n} \left( \frac{Er \times So}{Eo} \right) + \sum_{i=1}^{n} \frac{So}{Eo} \]  \hspace{1cm} (Eq. 1b) \\

\[ \text{AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.} \]

\[ Er = \text{Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, } i, \text{ in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, } Eadj, \text{ determined according to §63.7533 for that unit.} \]

\[ So = \text{Maximum steam output capacity of unit, } i, \text{ in units of million Btu per hour, as defined in §63.7575.} \]

\[ n = \text{Number of units participating in the emissions averaging option.} \]

\[ 1.1 = \text{Required discount factor.} \]

\[ \text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^{n} (Er \times So) + \sum_{i=1}^{n} So \]  \hspace{1cm} (Eq. 1c) \\

Where:

\[ \text{AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.} \]

\[ Er = \text{Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, } i, \text{ in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, } Eadj, \text{ determined according to §63.7533 for that unit.} \]

\[ Eo = \text{Maximum electric generating output capacity of unit, } i, \text{ in units of megawatt hour, as defined in §63.7575.} \]

\[ n = \text{Number of units participating in the emissions averaging option.} \]

\[ 1.1 = \text{Required discount factor.} \]

(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.

\[ \text{AveWeightedEmissions} = 1.1 \times \sum_{n=1}^{E} (Er \times Sm \times Cf) + \sum_{n=1}^{E} (Sm \times Cf) \]  \hspace{1cm} (Eq. 2) \\

Where:

\[ \text{AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.} \]
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 from the 12 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.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit
according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

\[\text{So} = \text{The steam output for that calendar month from unit, } i, \text{ in units of million Btu, as defined in §63.7575.}\]

\[n = \text{Number of units participating in the emissions averaging option.}\]

\[1.1 = \text{Required discount factor.}\]

\[\text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^{n} \left( Er \times So \right) \div \sum_{i=1}^{n} Eo \quad (\text{Eq. 3c})\]

Where:

\[\text{AveWeightedEmissions} = \text{Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.}\]

\[Er = \text{Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, } i, \text{ in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.}\]

\[Eo = \text{The electric generating output for that calendar month from unit, } i, \text{ in units of megawatt hour, as defined in §63.7575.}\]

\[n = \text{Number of units participating in the emissions averaging option.}\]

\[1.1 = \text{Required discount factor.}\]

(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.

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

Where:

\[\text{AveWeightedEmissions} = \text{average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.}\]

\[Er = \text{Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, } i, \text{ in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.}\]

\[Sa = \text{Actual steam generation for that calendar month by boiler, } i, \text{ in units of pounds.}\]

\[Cfi = \text{Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, } i.\]

\[1.1 = \text{Required discount factor.}\]
(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.

\[ E_{avg} = \frac{\sum_{i=1}^{12} ER_i}{12} \]

Where:

\( E_{avg} \) = 12-month rolling average emission rate, (pounds per million Btu heat input)

\( ER_i \) = 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.

\[
En = \sum_{i=1}^{n} (ELi \times Hi) + \sum_{i=1}^{n} Hi \quad \text{(Eq. 6)}
\]

Where:

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

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

\(Hi\) = Heat input from unit \(i\), MMBtu.

(2) Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).
(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.


§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.

(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.

(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. The relative accuracy testing must be at representative operating conditions.

(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.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.
(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see http://www.epa.gov/ttn/chief/ert/erttool.html/).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

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

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

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.
(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).
(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer’s specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer’s instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.
(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in 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.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM,
mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control
technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in 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.

(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.


§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525. 

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.
(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned ($Q_i$) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned ($C_i$).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$C_{\text{input}} = \sum_{i=1}^{n} (C_i \times Q_i) \quad (8\text{.\quad 7})$$

Where:

$C_{\text{input}} = \text{Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.}$

$C_i = \text{Arithmetic average concentration of chlorine in fuel type, } i, \text{ analyzed according to } \S 63.7521, \text{ in units of pounds per million Btu.}$

$Q_i = \text{Fraction of total heat input from fuel type, } i, \text{ based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for } Q_i. \text{ For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.}$

$n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.}$

(2) You must establish the maximum mercury fuel input level ($Mercury_{\text{input}}$) 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 ($HGi$).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

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

Where:

$Mercury_{\text{input}} = \text{Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.}$

$HGi = \text{Arithmetic average concentration of mercury in fuel type, } i, \text{ analyzed according to } \S 63.7521, \text{ in units of pounds per million Btu.}$

$Q_i = \text{Fraction of total heat input from fuel type, } i, \text{ based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for } Q_i. \text{ For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.}$

$n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.}$
(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

\[ TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \]  

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = 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 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 TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.
(1) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of 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.

\[ \bar{X} = \frac{1}{n} \sum_{i=1}^{n} X_i \]

\[ \bar{Y} = \frac{1}{n} \sum_{i=1}^{n} Y_i \]  \hspace{1cm} (Eq. 10)

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.

\[ R = \frac{Y}{(X_i - z)} \]  \hspace{1cm} (Eq. 11)
Where:

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

\( Y_1 = \) the three run average lb/MMBtu PM concentration,

\( X_1 = \) the three run average milliamp output from 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.

\[
O_h = z + \frac{0.75L}{R} \quad (\text{Eq. 12})
\]

Where:

\( O_h = \) 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.

\[
O_h = \frac{1}{n} \sum_{i=1}^{n} X_i \quad (\text{Eq. 13})
\]

Where:

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

\( n = \) the number of data points, and

\( O_h = \) your site specific operating limit, in milliamps.

(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.

\[
30-\text{day} = \frac{\sum_{i=1}^{n} H_{pi}}{n} \quad (\text{Eq. 14})
\]
Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in 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.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO₂ CEMS is to install and operate the SO₂ according to the requirements in §63.7525(m) establish a maximum SO₂ emission rate equal to the highest hourly average SO₂ measurement during the most recent three-run performance test for HCl.
(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

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

Where:

\[ P_{90} = \text{90th percentile confidence level pollutant concentration, in pounds per million Btu.} \]

\[ \text{Mean} = \text{Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.} \]

\[ \text{SD} = \text{Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.} \]

\[ t = \text{t distribution critical value for 90th percentile (t_{0.1}) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.} \]

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

\[ HCl = \sum_{i=1}^{n} (C_{i90} \times Q_i \times 1.028) \quad (\text{Eq. 16}) \]

Where:

\[ HCl = \text{HCl emission rate from the boiler or process heater in units of pounds per million Btu.} \]

\[ C_{i90} = \text{90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.} \]

\[ Q_i = \text{Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.} \]

\[ n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.} \]

\[ 1.028 = \text{Molecular weight ratio of HCl to chlorine.} \]

(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.

\[ \text{Mercury} = \sum_{i=1}^{n} (Hg_{i90} \times Q_i) \quad (\text{Eq. 17}) \]
Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

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.

\[ \text{Metals} = \sum_{i=1}^{n} (\text{TSMi90i} \times \text{Qi}) \quad (\text{Eq. 18}) \]

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 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.

Qi = 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 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 TSM content.

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 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 fuels.

(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.
(i) If you opt to comply with the alternative SO₂ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO₂ CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO₂ operating limit by collecting the maximum hourly SO₂ emission rate on the SO₂ CEMS during the paired 3-run test for HCl. The maximum SO₂ operating limit is equal to the highest hourly average SO₂ concentration measured during the HCl performance test.


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

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 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:

\[
EC_{\text{Credits}} = \left( \sum_{i = 1}^{n} EIS_{\text{actual}} \right) + EI_{\text{baseline}} \quad (\text{Eq. 19})
\]

Where:

\( EC_{\text{Credits}} \) = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

\( EIS_{\text{actual}} \) = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

\( EI_{\text{baseline}} \) = 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.

\[
E_{\text{eq}} = E_{\text{actual}} \times (1 - EC_{\text{Credits}}) \quad (\text{Eq. 20})
\]

Where:
E_{adj} = \text{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} = \text{Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.}

ECredits = \text{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.


Continuous Compliance Requirements

§63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

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

(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.


§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.
(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using
Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(ii) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in 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.

(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).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

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

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;
(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject;

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

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date 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.
(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the
CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 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.
(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.


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

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.
(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(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.

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

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits.

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in 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.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

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

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

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

(4) The date upon which you will commence combusting solid waste.
(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.


§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.
(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

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

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 9 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 18 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).

(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 if startup and shutdown, the compliance report must additionally contain the
information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you
deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the
corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was
completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at
an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit,
the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this
section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).
(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

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

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

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

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

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

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

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (http://www.epa.gov/ttn/chief/cedri/index.html), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.


§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

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

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

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

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

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

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

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.
(d) For each boiler or process heater subject to an emission limit in 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.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 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.

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

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning
the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

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

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.
(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.


§63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

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

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.
§63.7575 What definitions apply to this subpart?

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

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

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, government 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 ofcombusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Fluidized bed boiler with an integrated fluidized bed heat exchanger** means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.
Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

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

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

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

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

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

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

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

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

Minimum sorbent injection rate means:

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

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.
**Minimum total secondary electric power** means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

**Natural gas** means:

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

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

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

4. Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8.

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

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

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

**Other gas 1 fuel** means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum 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 (S1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S2), 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, S1, S2, 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.

\[
SO_m = S_1 + S_2 + (MW(3) \times CFn)
\]

Eq. 21

Where:

SOm = Total steam output for multi-function boiler, MMBtu

S1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S2 = 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/bio-based 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/bio-based 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 excluded 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](http://www.iso.org/iso/home.htm), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 [http://www.standards.org.au](http://www.standards.org.au)), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8966 9001, [http://www.bsigroup.com](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](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](http://www.cen.eu/cen)), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 002, Duesseldorf, Germany, + 49 211 6214-230, [http://www.vdi.eu](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.


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

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...

<table>
<thead>
<tr>
<th>Subcategory</th>
<th>Pollutant</th>
<th>Emission Limit</th>
<th>Alternative Limit</th>
<th>Sampling Volume or Test Run Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. Units designed to burn coal/solid fossil fuel</td>
<td>Mercury</td>
<td>8.0E-07 lb per MMBtu of heat input</td>
<td>8.7E-07 lb per MMBtu of steam output or 1.1E-05 lb per MWh</td>
<td>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 collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input or (2.3E-05 lb per MMBtu of heat input)</td>
<td>1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>4. Stokers/others designed to burn coal/solid fossil fuel</td>
<td>Carbon monoxide (CO) (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
</tbody>
</table>
If your boiler or process heater is in this subcategory...

<table>
<thead>
<tr>
<th>For the following pollutants...</th>
<th>The emissions must not exceed the following emission limits, except during startup and shutdown...</th>
<th>Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown...</th>
<th>Using this specified sampling volume or test run duration...</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td>3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
</tbody>
</table>

8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel

<table>
<thead>
<tr>
<th>a. CO</th>
<th>460 ppm by volume on a dry basis corrected to 3 percent oxygen</th>
<th>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
</tbody>
</table>

9. Fluidized bed units designed to burn biomass/bio-based solids

<table>
<thead>
<tr>
<th>a. CO (or CEMS)</th>
<th>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), 30-day rolling average</th>
<th>2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>9.8E-03 lb per MMBtu of heat input; or (8.3E-05 lb per MMBtu of heat input)</td>
<td>1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 lb per MMBtu of steam output or 1.2E-03 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

10. Suspension burners designed to burn biomass/bio-based solids

<table>
<thead>
<tr>
<th>a. CO (or CEMS)</th>
<th>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), 10-day rolling average</th>
<th>1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>If your boiler or process heater is in this subcategory</td>
<td>For the following pollutants</td>
<td>The emissions must not exceed the following emission limits, except during startup and shutdown</td>
<td>Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown</td>
</tr>
<tr>
<td>----------------------------------------------------------</td>
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</tr>
<tr>
<td>11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids</td>
<td>a. CO (or CEMS)</td>
<td>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, 10-day rolling average)</td>
<td>3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)</td>
<td>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)</td>
</tr>
<tr>
<td>12. Fuel cell units designed to burn biomass/bio-based solids</td>
<td>a. CO</td>
<td>910 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>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)</td>
</tr>
<tr>
<td>13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1.4 lb per MMBtu of steam output; 12 lb per MWh; 3-run average</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
</tr>
<tr>
<td>14. Units designed to burn liquid fuel</td>
<td>a. HCl</td>
<td>4.4E-04 lb per MMBtu of heat input</td>
<td>4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh</td>
</tr>
</tbody>
</table>
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 . . .
---|---|---|---|---
| b. Mercury | 4.8E-07 lb per MMBtu of heat input | 5.3E-07 lb per MMBtu of steam output or 6.7E-06 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, collect a minimum of 4 dscm.
| 15. Units designed to burn heavy liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time.
| b. Filterable PM (or TSM) | 1.3E-02 lb per MMBtu of heat input; or (7.5E-05 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 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | 1.2E-03 lb per MMBtu of steam output or 1.6E-02 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.
<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory</th>
<th>For the following pollutants</th>
<th>The emissions must not exceed the following emission limits, except during startup and shutdown</th>
<th>Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown</th>
<th>Using this specified sampling volume or test run duration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>c. Mercury</td>
<td>7.9E-06 lb per MMBtu of heat input</td>
<td>1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh</td>
<td>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, collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td></td>
<td>d. Filterable PM (or TSM)</td>
<td>6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

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.

ªIncorporated by reference, see §63.14.

ªIf 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.

ªAn 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.

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

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]

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during startup and shutdown . . .</th>
<th>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>2.2E-02 lb per MMBtu of heat input</td>
<td>2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh</td>
<td>For M26A, Collect a minimum of 1 dscm per run; for M26E, collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>5.7E-06 lb per MMBtu of heat input</td>
<td>6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td>2. Units design to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)</td>
<td>4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (6.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>4. Stokers/others designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>If your boiler or process heater is in this subcategory. . .</td>
<td>For the following pollutants . . .</td>
<td>The emissions must not exceed the following emission limits, except during startup and shutdown . . .</td>
<td>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .</td>
<td>Using this specified sampling volume or test run duration . . .</td>
</tr>
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</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</td>
<td>a. CO</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>9. Fluidized bed units designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>If your boiler or process heater is in this subcategory</td>
<td>For the following pollutants</td>
<td>The emissions must not exceed the following emission limits, except during startup and shutdown</td>
<td>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown</td>
<td>Using this specified sampling volume or test run duration</td>
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</tr>
<tr>
<td>10. Suspension burners designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>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,(^*) 10-day rolling average)</td>
<td>1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>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,(^*) 10-day rolling average)</td>
<td>8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>12. Fuel cell units designed to burn biomass/bio-based solid</td>
<td>a. CO</td>
<td>1,100 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>2.4 lb per MMBtu of steam output or 12 lb per MWh</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>13. Hybrid suspension grate units designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>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,(^*) 30-day rolling average)</td>
<td>3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>If your boiler or process heater is in this subcategory</td>
<td>For the following pollutants</td>
<td>The emissions must not exceed the following emission limits, except during startup and shutdown</td>
<td>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown</td>
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<td>-------------------------------------------------</td>
</tr>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>14. Units designed to burn liquid fuel</td>
<td>a. HCl</td>
<td>1.1E-03 lb per MMBtu of heat input</td>
<td>1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh</td>
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<tr>
<td></td>
<td>b. Mercury</td>
<td>2.0E-06a lb per MMBtu of heat input</td>
<td>2.5E-06a lb per MMBtu of steam output or 2.8E-05 lb per MWh</td>
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<td></td>
<td></td>
<td>For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Units designed to burn heavy liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16. Units designed to burn light liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>7.9E-03a lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)</td>
<td>9.6E-03a lb per MMBtu of steam output or 1.1E-01a lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>17. Units designed to burn liquid fuel that are non-continental units</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)</td>
<td>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)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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 . . .  
---|---|---|---|---
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 D6784b 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.  

\(^{a}\)If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

\(^{b}\)Incorporated by reference, see §63.14.

\(^{c}\)An owner or operator may 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 CO\(_2\) correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO\(_2\) being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

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

As stated in §63.7500, you must comply with the following applicable work practice standards:

<table>
<thead>
<tr>
<th>If your unit is . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.</td>
<td>Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.</td>
</tr>
<tr>
<td>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 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.</td>
<td>Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.</td>
</tr>
<tr>
<td>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.</td>
<td>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.</td>
</tr>
<tr>
<td>4. An existing boiler or process heater located at a major source facility, not including limited use units.</td>
<td>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:</td>
</tr>
<tr>
<td>a. A visual inspection of the boiler or process heater system.</td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>If your unit is . . .</td>
<td>You must meet the following . . .</td>
</tr>
<tr>
<td>---------------------</td>
<td>----------------------------------</td>
</tr>
<tr>
<td></td>
<td>d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>f. A list of cost-effective energy conservation measures that are within the facility's control.</td>
</tr>
<tr>
<td></td>
<td>g. A list of the energy savings potential of the energy conservation measures identified.</td>
</tr>
<tr>
<td></td>
<td>h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.</td>
</tr>
</tbody>
</table>

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

| a. You must operate all CMS during startup. |
| b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. |
| c. You have the option of complying using either of the following work practice standards. |
|   (1) If you choose to comply using 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 |
|   (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. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). |
| d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555. |
If your unit is . . .

You must meet the following . . .

6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown

You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device.

If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultralow 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.

As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the “fuel firing + 1 hour” requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (e.g., scrubber).


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

As stated in §63.7500, you must comply with the applicable operating limits:

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

<table>
<thead>
<tr>
<th>When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS</td>
<td>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.</td>
</tr>
<tr>
<td>2. Wet acid gas (HCl) scrubber control on a boiler or process heater not using a HCl CEMS</td>
<td>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.</td>
</tr>
<tr>
<td>3. Fabric filter control on a boiler or process heater not using a PM CPMS</td>
<td>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</td>
</tr>
</tbody>
</table>
When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . . You must meet these operating limits . . .

<table>
<thead>
<tr>
<th>4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS</th>
<th>b. 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).</th>
</tr>
</thead>
<tbody>
<tr>
<td>5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS</td>
<td>a. 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.</td>
</tr>
<tr>
<td>6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS</td>
<td>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).</td>
</tr>
<tr>
<td>7. Performance testing</td>
<td>For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.</td>
</tr>
<tr>
<td>8. Oxygen analyzer system</td>
<td>For boilers and process heaters subject to an 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).</td>
</tr>
<tr>
<td>9. SO₂ CEMS</td>
<td>For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO₂ CEMS, maintain the 30-day rolling average SO₂ emission rate at or below the highest hourly average SO₂ concentration measured during the HCl performance test, as specified in Table 8.</td>
</tr>
</tbody>
</table>

*A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]
Table 5 to Subpart DDDD of Part 63—Performance Testing Requirements

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

<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>You must . . .</th>
<th>Using, as appropriate . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Filterable PM</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
</tbody>
</table>
|                                                              | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.
|                                                              | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
|                                                              | e. Measure the PM emission concentration | Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter. |
|                                                              | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 2. TSM                                                        | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
|                                                              | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter. |
|                                                              | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.
<p>|                                                              | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
|                                                              | e. Measure the TSM emission concentration | Method 29 at 40 CFR part 60, appendix A-8 of this chapter |
|                                                              | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 3. Hydrogen chloride                                          | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
|                                                              | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter. |</p>
<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>You must . . .</th>
<th>Using, as appropriate . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the hydrogen chloride emission concentration</td>
<td>Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>4. Mercury</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the mercury emission concentration</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

Table 6 to Subpart DDDD of Part 63—Fuel Analysis Requirements

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

<table>
<thead>
<tr>
<th>To conduct a fuel analysis for the following pollutant . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Mercury</td>
<td>a. Collect fuel samples</td>
<td>Procedure in §63.7521(c) or ASTM D5192, ASTM D7430, ASTM D6883, ASTM D2234/D2234M, (for coal) or ASTM D6323 (for solid), or ASTM D4177 (for liquid), or ASTM D4057 (for liquid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare composited fuel samples</td>
<td>EPA SW-846-3050B, ASTM D2013/D2013M, ASTM D5198 (for biomass), or EPA 3050 (for solid fuel), or EPA 821-R-01-013 (for liquid or solid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>d. Determine heat content of the fuel type</td>
<td>ASTM D5865 (for coal) or ASTM E711 (for biomass), or ASTM D5864 (for liquids and other solids, or ASTM D240 or equivalent.</td>
</tr>
<tr>
<td></td>
<td>e. Determine moisture content of the fuel type</td>
<td>ASTM D3173, ASTM E871, ASTM D5864, ASTM D240, or ASTM D95 (for liquid fuels), or ASTM D4006 (for liquid fuels), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>f. Measure mercury concentration in fuel sample</td>
<td>ASTM D6722, EPA SW-846-7471B, EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470A (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>g. Convert concentration into units of pounds of mercury per MMBtu of heat content</td>
<td>For fuel mixtures use Equation 8 in §63.7530.</td>
</tr>
<tr>
<td>2. HCl</td>
<td>a. Collect fuel samples</td>
<td>Procedure in §63.7521(c) or ASTM D5192, ASTM D7430, ASTM D6883, ASTM D2234/D2234M, (for coal) or ASTM D6323 (for coal or biomass), ASTM D4177 (for liquid fuels) or ASTM D4057 (for liquid fuels), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare composited fuel samples</td>
<td>EPA SW-846-3050B, ASTM D2013/D2013M, ASTM D5198 (for biomass), or EPA 3050 (for solid fuel), or EPA SW-846-5050A (for solid fuel), or EPA SW-846-9056A or SW-846-9076A (for solids or liquids) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>d. Determine heat content of the fuel type</td>
<td>ASTM D5865 (for coal) or ASTM E711 (for biomass), ASTM D5864, ASTM D240 or equivalent.</td>
</tr>
<tr>
<td></td>
<td>e. Determine moisture content of the fuel type</td>
<td>ASTM D3173, ASTM E871, ASTM D5864, ASTM D240, or ASTM D95 (for liquid fuels), or ASTM D4006 (for liquid fuels), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>f. Measure chlorine concentration in fuel sample</td>
<td>EPA SW-846-9250, ASTM D6721, ASTM D4208 (for coal), or EPA SW-846-5050A or ASTM E776 (for solid fuel), or EPA SW-846-9056A or SW-846-9076A (for solids or liquids) or equivalent.</td>
</tr>
</tbody>
</table>
To conduct a fuel analysis for the following pollutant...

<table>
<thead>
<tr>
<th>You must . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>g. Convert concentrations into units of pounds of HCl per MMBtu of heat content</td>
<td>For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.</td>
</tr>
</tbody>
</table>

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, ASTM D6350, ISO 6978-1:2003(E), or ISO 6978-2:2003(E), or EPA-1631 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 or equivalent. |

4. TSM

| a. Collect fuel samples | Procedure in §63.7521(c) or ASTM D5192, or ASTM D7430, or ASTM D6883, or ASTM D2234/D2234M (for coal) or ASTM D6323 (for coal or biomass), or ASTM D4177, (for liquid fuels) or ASTM D4057 (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 (for solid samples), ASTM D2013/D2013M (for coal), ASTM D5198 or TAPPI T266 (for biomass), or EPA 3050 or equivalent. |
| d. Determine heat content of the fuel type | ASTM D5865 (for coal) or ASTM E711 (for biomass), or ASTM D5864 for liquids and other solids, or ASTM D240 or equivalent. |
| e. Determine moisture content of the fuel type | ASTM D3173 or ASTM E871, or D5864, or ASTM D240, or ASTM D95 (for liquid fuels), or ASTM D4006 (for liquid fuels), or ASTM D4177 (for liquid fuels) or ASTM D4057 (for liquid fuels), or equivalent. |
| f. Measure TSM concentration in fuel sample | ASTM D3683, or ASTM D4606, or ASTM D6357 or EPA 200.8 or EPA SW-846-6020, or EPA SW-846-6020A, or EPA SW-846-6010C, or EPA 7060 or EPA 7060A (for arsenic only), or EPA SW-846-7740 (for selenium only). |
| g. Convert concentrations into units of pounds of TSM per MMBtu of heat content | For fuel mixtures use Equation 9 in §63.7530. |

\[a\] Incorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]
Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

<table>
<thead>
<tr>
<th>If you have an applicable emission limit for . . .</th>
<th>And your operating limits are based on . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
<th>According to the following requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. PM, TSM, or mercury</td>
<td>a. Wet scrubber operating parameters</td>
<td>i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)</td>
<td>(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test</td>
<td>(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.</td>
</tr>
<tr>
<td></td>
<td>b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)</td>
<td>i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)</td>
<td>(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test</td>
<td>(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.</td>
</tr>
<tr>
<td></td>
<td>c. Opacity</td>
<td>i. Establish a site-specific maximum opacity level</td>
<td>(1) Data from the opacity monitoring system during the PM performance test</td>
<td>(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (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. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.</td>
</tr>
<tr>
<td>If you have an applicable emission limit for . . .</td>
<td>And your operating limits are based on . . .</td>
<td>You must . . .</td>
<td>Using . . .</td>
<td>According to the following requirements</td>
</tr>
<tr>
<td>--------------------------------------------------</td>
<td>--------------------------------------------</td>
<td>---------------</td>
<td>-------------</td>
<td>------------------------------------------</td>
</tr>
<tr>
<td>2. HCl</td>
<td>a. Wet scrubber operating parameters</td>
<td>i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)</td>
<td>(1) Data from the pH and liquid flow-rate monitors and the HCl performance test</td>
<td>(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.</td>
</tr>
<tr>
<td></td>
<td>b. Dry scrubber operating parameters</td>
<td>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</td>
<td>(1) Data from the sorbent injection rate monitors and HCl or mercury performance test</td>
<td>(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.</td>
</tr>
<tr>
<td></td>
<td>c. Alternative Maximum SO₂ emission rate</td>
<td>i. Establish a site-specific maximum SO₂ emission rate operating limit according to §63.7530(b)</td>
<td>(1) Data from SO₂ CEMS and the HCl performance test</td>
<td>(a) You must collect the SO₂ emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO₂ emission rate is equal to the highest hourly average SO₂ emission rate measured during the most recent HCl performance tests.</td>
</tr>
</tbody>
</table>
### Table of Emission Limits and Operating Requirements

| 3. Mercury | a. Activated carbon injection | i. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b) | (1) Data from the activated carbon rate monitors and mercury performance test | (a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate. |

| 4. Carbon monoxide for which compliance is demonstrated by a performance test | a. Oxygen | i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b) | (1) Data from the oxygen analyzer system specified in §63.7525(a) | (a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit. |

| 5. Any pollutant for which compliance is demonstrated by a performance test | a. Boiler or process heater operating load | i. Establish a unit specific limit for maximum operating load according to §63.7520(c) | (1) Data from the operating load monitors or from steam generation monitors | (a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit. |

---

*aOperating limits must be confirmed or reestablished during performance tests.*
If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

[80 FR 72827, Nov. 20, 2015]

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

As stated in §63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
</table>
| 1. Opacity | a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and  
  b. Reducing the opacity monitoring data to 6-minute averages; and  
  c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation. |
| 2. PM CPMS | a. Collecting the PM CPMS output data according to §63.7525;  
  b. Reducing the data to 30-day rolling averages; and  
  c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4). |
| 3. Fabric Filter Bag Leak Detection Operation | Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met. |
| 4. Wet Scrubber Pressure Drop and Liquid Flow-rate | a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and  
  b. Reducing the data to 30-day rolling averages; and  
  c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(b). |
| 5. Wet Scrubber pH | a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and  
  b. Reducing the data to 30-day rolling averages; and  
  c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b). |
| 6. Dry Scrubber Sorbent or Carbon Injection Rate | a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and  
  b. Reducing the data to 30-day rolling averages; and  
  c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575. |
| 7. Electrostatic Precipitator Total Secondary Electric Power Input | a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and  
  b. Reducing the data to 30-day rolling averages; and |
If you must meet the following operating limits or work practice standards . . .
You must demonstrate continuous compliance by . . .

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>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).</td>
<td>a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and</td>
</tr>
<tr>
<td>b. Reduce the data to 12-month rolling averages; and</td>
<td>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.</td>
</tr>
<tr>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>

8. Emission limits using fuel analysis

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and</td>
<td>a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and</td>
</tr>
<tr>
<td>b. Reduce the data to 12-month rolling averages; and</td>
<td>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.</td>
</tr>
<tr>
<td>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.</td>
<td>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.</td>
</tr>
</tbody>
</table>

9. Oxygen content

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>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).</td>
<td>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).</td>
</tr>
<tr>
<td>b. Reducing the data to 30-day rolling averages; and</td>
<td>b. Reducing the data to 30-day rolling averages; and</td>
</tr>
<tr>
<td>c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.</td>
<td>c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.</td>
</tr>
</tbody>
</table>

10. Boiler or process heater operating load

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Collecting operating load data or steam generation data every 15 minutes.</td>
<td>a. Collecting operating load data or steam generation data every 15 minutes.</td>
</tr>
<tr>
<td>b. Reducing the data to 30-day rolling averages; and</td>
<td>b. Reducing the data to 30-day rolling averages; and</td>
</tr>
<tr>
<td>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).</td>
<td>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).</td>
</tr>
</tbody>
</table>

11. SO₂ emissions using SO₂ CEMS

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Collecting the SO₂ CEMS output data according to §63.7525;</td>
<td>a. Collecting the SO₂ CEMS output data according to §63.7525;</td>
</tr>
<tr>
<td>b. Reducing the data to 30-day rolling averages; and</td>
<td>b. Reducing the data to 30-day rolling averages; and</td>
</tr>
<tr>
<td>c. Maintaining the 30-day rolling average SO₂ CEMS emission rate to a level at or below the highest hourly SO₂ rate measured during the HCl performance test according to §63.7530.</td>
<td>c. Maintaining the 30-day rolling average SO₂ CEMS emission rate to a level at or below the highest hourly SO₂ rate measured during the HCl performance test according to §63.7530.</td>
</tr>
</tbody>
</table>


**Table 9 to Subpart DDDDD of Part 63—Reporting Requirements**

As stated in §63.7550, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>If you must submit a(n)</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.7550(c)(1) through (5); and</td>
<td>Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).</td>
</tr>
</tbody>
</table>
You must submit a(n) | The report must contain . . . | You must submit the report . . .
--- | --- | ---
b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and

c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and

d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), or otherwise not operating, the report must contain the information in §63.7550(e)


Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

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

<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Applies to subpart DDDDD</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>Applicability</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes. Additional terms defined in §63.7575</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and Abbreviations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited Activities and Circumvention</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.5</td>
<td>Preconstruction Review and Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(a), (b)(1)-(b)(5), (b)(7), (c)</td>
<td>Compliance with Standards and Maintenance Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(e)(1)(i)</td>
<td>General duty to minimize emissions.</td>
<td>No. See §63.7500(a)(3) for the general duty requirement.</td>
</tr>
<tr>
<td>§63.6(e)(1)(ii)</td>
<td>Requirement to correct malfunctions as soon as practicable.</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(e)(3)</td>
<td>Startup, shutdown, and malfunction plan requirements.</td>
<td>No.</td>
</tr>
<tr>
<td>Citation</td>
<td>Subject</td>
<td>Applies to subpart DDDDD</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------------------------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(f)(2) and (3)</td>
<td>Compliance with non-opacity emission standards.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(g)</td>
<td>Use of alternative standards</td>
<td>Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).</td>
</tr>
<tr>
<td>§63.6(h)(1)</td>
<td>Startup, shutdown, and malfunction exemptions to opacity standards.</td>
<td>No. See §63.7500(a).</td>
</tr>
<tr>
<td>§63.6(h)(2) to (h)(9)</td>
<td>Determining compliance with opacity emission standards</td>
<td>No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.</td>
</tr>
<tr>
<td>§63.6(i)</td>
<td>Extension of compliance</td>
<td>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.</td>
</tr>
<tr>
<td>§63.6(j)</td>
<td>Presidential exemption.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(a), (b), (c), and (d)</td>
<td>Performance Testing Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Conditions for conducting performance tests</td>
<td>No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c).</td>
</tr>
<tr>
<td>§63.7(e)(2)-(e)(9), (f), (g), and (h)</td>
<td>Performance Testing Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(a) and (b)</td>
<td>Applicability and Conduct of Monitoring</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>General duty to minimize emissions and CMS operation</td>
<td>No. See §63.7500(a)(3).</td>
</tr>
<tr>
<td>§63.8(c)(1)(ii)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Startup, shutdown, and malfunction plans for CMS</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(c)(2) to (c)(9)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(d)(1) and (2)</td>
<td>Monitoring Requirements, Quality Control Program</td>
<td>Yes.</td>
</tr>
<tr>
<td>Citation</td>
<td>Subject</td>
<td>Applies to subpart DDDDD</td>
</tr>
<tr>
<td>-------------------</td>
<td>----------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>§63.8(d)(3)</td>
<td>Written procedures for CMS</td>
<td>Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.</td>
</tr>
<tr>
<td>§63.8(e)</td>
<td>Performance evaluation of a CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(f)</td>
<td>Use of an alternative monitoring method.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(g)</td>
<td>Reduction of monitoring data</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.9</td>
<td>Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(a), (b)(1)</td>
<td>Recordkeeping and Reporting Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(i)</td>
<td>Recordkeeping of occurrence and duration of startups or shutdowns</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(ii)</td>
<td>Recordkeeping of malfunctions</td>
<td>No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iii)</td>
<td>Maintenance records</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iv) and (v)</td>
<td>Actions taken to minimize emissions during startup, shutdown, or malfunction</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vi)</td>
<td>Recordkeeping for CMS malfunctions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vii) to (xiv)</td>
<td>Other CMS requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(3)</td>
<td>Recordkeeping requirements for applicability determinations</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(c)(1) to (9)</td>
<td>Recordkeeping for sources with CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(10) and (11)</td>
<td>Recording nature and cause of malfunctions, and corrective actions</td>
<td>No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.</td>
</tr>
<tr>
<td>§63.10(c)(12) and (13)</td>
<td>Recordkeeping for sources with CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(15)</td>
<td>Use of startup, shutdown, and malfunction plan</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(1) and (2)</td>
<td>General reporting requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(3)</td>
<td>Reporting opacity or visible emission observation results</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(4)</td>
<td>Progress reports under an extension of compliance</td>
<td>Yes.</td>
</tr>
</tbody>
</table>
### 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

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td>2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis</td>
<td>a. Mercury</td>
<td>8.0E-07(^a) lb per MMBtu of heat input</td>
<td>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.</td>
</tr>
<tr>
<td>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</td>
<td>a. Mercury</td>
<td>2.0E-06 lb per MMBtu of heat input</td>
<td>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.</td>
</tr>
<tr>
<td>If your boiler or process heater is in this subcategory</td>
<td>For the following pollutants</td>
<td>The emissions must not exceed the following emission limits, except during periods of startup and shutdown</td>
<td>Using this specified sampling volume or test run duration</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>4. Units design to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>5. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>6. Stokers designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>7. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>9. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</td>
<td>a. CO</td>
<td>560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>11. Fluidized bed units designed to burn biomass/bio-based solids</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
</tbody>
</table>
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 . . . |
---|---|---|---|
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, 10-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 lb per MMBtu of heat input) | Collect a minimum of 3 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, 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. |
14. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| b. Filterable PM (or TSM) | 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids | a. CO (or CEMS) | 1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 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 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 D6784b, collect a minimum of 4 dscm. |
If your boiler or process heater is in this subcategory . . .  | For the following pollutants . . .  | The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .  | Using this specified sampling volume or test run duration . . .  
---|---|---|---  
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 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)  | Collect a minimum of 3 dscm per run.  
19. Units designed to burn liquid fuel that are non-continental units  | a. CO  | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test  | 1 hr minimum sampling time.  
|  | b. Filterable PM (or TSM)  | 2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)  | Collect a minimum of 4 dscm per run.  
20. Units designed to burn gas 2 (other) gases  | a. CO  | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 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, 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.  

If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

Incorporated by reference, see §63.14.

An 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]

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

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>3.5E-06 lb per MMBtu of heat input</td>
<td>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 collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td>2. Units design to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>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,³ 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>4. Stokers designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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,³ 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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,³ 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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,³ 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>a. CO (or CEMS)</td>
<td>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,³ 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
</tbody>
</table>
If your boiler or process heater is in this subcategory . . . | For the following pollutants . . . | The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . . | Using this specified sampling volume or test run duration . . . |
--- | --- | --- | --- |
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel | a. CO | 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. |
| b. Filterable PM (or TSM) | | | |
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, 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 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, 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, 10-day rolling average) | 1 hr minimum sampling time. |
| b. Filterable PM (or TSM) | 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
12. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen, 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. |
| b. Filterable PM (or TSM) | | | |
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, 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. |
<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>b. Mercury</td>
<td>4.8E-07\textsuperscript{a} lb per MMBtu of heat input</td>
<td>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\textsuperscript{a} collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>15. Units designed to burn heavy liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>16. Units designed to burn light liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.3E-03 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>17. Units designed to burn liquid fuel that are non-continental units</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td>18. Units designed to burn gas 2 (other) gases</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. HCl</td>
<td>1.7E-03 lb per MMBtu of heat input</td>
<td>For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td></td>
<td>c. Mercury</td>
<td>7.9E-06 lb per MMBtu of heat input</td>
<td>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\textsuperscript{a} collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td></td>
<td>d. Filterable PM (or TSM)</td>
<td>6.7E-03 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

\textsuperscript{a}If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

\textsuperscript{b}Incorporated by reference, see §63.14.
An 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]

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

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>8.6E-07 lb per MMBtu of heat input</td>
<td>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 collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>2. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>3. Stokers designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>4. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>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, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
</tbody>
</table>
If your boiler or process heater is in this subcategory . . . | For the following pollutants . . . | The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . . | Using this specified sampling volume or test run duration . . . |
---|---|---|---|
6. Stokers/sloped grate/others designed to burn wet biomass fuel | 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. |
7. Stokers/sloped grate/others designed to burn kiln-dried 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, 10-day rolling average) | 1 hr minimum sampling time. |
8. Fluidized bed units designed to burn biomass/bio-based solids | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
9. Suspension burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 460 ppm by volume on a dry basis corrected to 3 percent oxygen | 1 hr minimum sampling time. |
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | 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. |
11. Fuel cell units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 910 ppm by volume on a dry basis corrected to 3 percent oxygen | 1 hr minimum sampling time. |
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids | b. Filterable PM (or TSM) | 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, 30-day rolling average) | 1 hr minimum sampling time. |
If your boiler or process heater is in this subcategory . . .

<table>
<thead>
<tr>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

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-07a 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 D6784b collect a minimum of 4 dscm. |

14. Units designed to burn heavy liquid fuel

| a. CO (or CEMS)                   | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average) | 1 hr minimum sampling time. |

15. Units designed to burn light liquid fuel

| a. CO (or CEMS)                   | 130a 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, 1-day block average) | 1 hr minimum sampling time. |

| b. Filterable PM (or TSM)         | 1.1E-03a 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 D6784b 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. |

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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 and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to §63.7515 if all of the other provision of
§63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

b Incorporated by reference, see §63.14.

c An owner or operator may 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.

Attachment E

Part 70 Operating Permit No: 147-40656-00020

[Downloaded from the eCFR on April 7, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

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

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Source: 77 FR 9464, Feb. 16, 2012, unless otherwise noted.

What This Subpart Covers

§63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.

§63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in §63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in §63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in §63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

§63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a major source stationary combustion turbine subject to subpart YYYY of this part and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in §63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in §63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under subpart DDDDD of this part, if it otherwise meets the applicability provisions in that rule.

[77 FR 9464, Feb. 16, 2012, as amended at 81 FR 20180, Apr. 6, 2016]

§63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in §63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in §63.10030 according to the schedule in §63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under §63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in §63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.
(2) An EGU that commenced reconstruction after May 3, 2011.

(b) [Reserved]


Emission Limitations and Work Practice Standards

§63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in §63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in §63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under §63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

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

(c) You may use the alternate SO2 limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and an SO2 continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO2 CEMS installed on the EGU consistent with §63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 81 FR 20180, Apr. 6, 2016]
General Compliance Requirements

§63.10000   What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to this subpart during periods of startup or shutdown.

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

(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with §63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(1) Your EGU’s control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(2) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU’s annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

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

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

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

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCI CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCI CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry
flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO₂) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO₂ emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(A) You may choose to use separate sorbent trap monitoring systems to comply with this subpart: One sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods.

(B) You may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emissions limit at all times (including startup periods and shutdown periods) and to report average mercury concentration. You must follow the startup or shutdown requirements that follow and as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with §63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in §63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.
(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of §63.10010 (e.g., if the CMS was previously certified under another program).

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

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See §63.10010(a) for further details. For PM CPMS installations, follow the procedures in §63.10010(h).

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

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of §63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with §63.8(c)(7)(i) and for responding to out of control periods consistent with §§63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to §63.10021(e).

(f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.
(g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with §63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart and cease to operate in a manner that causes your unit to meet the definition of an EGU subject to this subpart, you must be in compliance with any newly applicable section 112 or 129 standards on the date you selected consistent with paragraphs (g) and (n) of this section.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source
(l) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(m) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.


§63.10001 [Reserved]

Testing and Initial Compliance Requirements

§63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) General requirements. For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and a gross output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, e.g., hourly gross output data (megawatts); establishment of operating limits according to §63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in §63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

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

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e., an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO₂ or PM CEMS, the initial performance test shall
consist of 30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90-boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this section. If the CMS is not certified prior to the compliance date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (i.e., 180 days after the applicable compliance date).

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO2 emissions limit in Table 1 or 2 to this subpart.

(ii) You must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO2, O2, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period.

(iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler operating day performance test must either be excluded from or included in the compliance demonstration as follows:

(A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations;

(B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; or

(C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in the compliance demonstrations.

(b) Performance testing requirements. If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in §63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in §63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.
(6) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

(c) Operating limits. In accordance with §63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) CMS requirements. If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO₂, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO₂, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO₂, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: For this calculation, the term \( E_{ij} \) in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

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

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.
(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) **Tune-ups.** All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to §63.10021(e).

(f) For an existing EGU without a neural network, a tune-up, following the procedures in §63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) **Low emitting EGUs.** The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to §63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in §63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in §63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-
boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO2 or O2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to paragraph 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to paragraph 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to paragraph 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO2 (or O2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m³ (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO2 or O2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in §63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values “Cₜ”, “Qₜ”, “Bₜ" and “(MW)ₜ" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(1) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10⁻⁶ to convert it to TBtu/hr; or

(2) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10⁻³ to convert it to GW; or

(3) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).
(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), “Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,” or


(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177-95 (Reapproved 2010), “Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,” including Annexes A1 through A6 and Appendices X1 and X2, or


(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or
(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in §63.10030.


§63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under §63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and §63.10007 at least every year.

(b) For affected units meeting the LEE requirements of §63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

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

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

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO2 CEMS to monitor compliance with the alternate equivalent SO2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in §63.10000(c)(2)(iii).

(f) Time between performance tests. (1) Notwithstanding the provisions of §63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

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

(ii) For annual testing:

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

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

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

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

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

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

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

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

(g) If you elect to demonstrate compliance using emissions averaging under §63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10021(e).

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

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


§63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).
(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in §63.10000(c), you must also establish an operating limit according to §63.10011(b), §63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO2 ppm by $1.66 \times 10^{-7}$;

(ii) Multiply HCl ppm by $9.43 \times 10^{-8}$;

(iii) Multiply HF ppm by $5.18 \times 10^{-8}$;

(iv) Multiply HAP metals concentrations (mg/dscm) by $6.24 \times 10^{-8}$; and

(v) Multiply Hg concentrations (µg/scm) by $6.24 \times 10^{-11}$.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases,
use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with $1.66 \times 10^{-7}$ lb/scf-ppm for SO$_2$, $9.43 \times 10^{-6}$ lb/scf-ppm for HCl (if an HCl CEMS is used), $5.18 \times 10^{-6}$ lb/scf-ppm for HF (if an HF CEMS is used), or $6.24 \times 10^{-8}$ lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining $C_h$ as the average SO$_2$, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the $10^3$ term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) If you elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

1) **Diluent cap values.** If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO$_2$ concentration is below the cap value or the measured O$_2$ concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for CO$_2$ or 19% for O$_2$.

(ii) For all other EGUs, you may use 5% for CO$_2$ or 14% for O$_2$.

2) **Default gross output.** If you use CEMS to continuously monitor Hg, HCl, HF, SO$_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (i.e., combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.
(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance (LEE) testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance (LEE) testing. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) Equations. Use the following equations when performing calculations for your EGU emissions averaging group:

(1) Group eligibility equations.

\[
WAER_p = \frac{\sum_{j=1}^{p} H_{erm_j} \times R_{mm_j}}{\left(\sum_{j=1}^{p} R_{mm_j}\right)} + \frac{\sum_{k=1}^{m} T_{eri_k} \times R_{mtk}}{\left(\sum_{k=1}^{m} R_{mtk}\right)}
\]  
\text{(Eq. 1a)}

Where:

\[WAER_p = \text{Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output},\]
\[H_{erm_j} = \text{hourly emission rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j},\]
\[R_{mm_j} = \text{Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j},\]
\[p = \text{number of EGUs in emissions averaging group that rely on CEMS},\]
\[T_{eri_k} = \text{Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k},\]
\[R_{mtk} = \text{Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k},\]
\[m = \text{number of EGUs in emissions averaging group that rely on emissions testing}.\]

\[
WAER_m = \frac{\sum \left[\left(\sum_{j=1}^{p} H_{erm_j} \times S_{mm_j} \times C_{mfj}\right) + \sum_{k=1}^{m} T_{eri_k} \times S_{mtk} \times C_{ftk}\right]}{\sum \left[\sum_{j=1}^{p} S_{mm_j} \times C_{mfj}\right] + \sum_{k=1}^{m} S_{mtk} \times C_{ftk}}
\]  
\text{(Eq. 1b)}

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,
Smm_{j} = \text{maximum steam generation, } lb_{\text{steam}/h} \text{ or } lb/\text{gross output, for EGU } j, \\
Cfm_{j} = \text{conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{\text{steam}} \text{ or } MWh/lb_{\text{steam}}) from EGU } j, \\
Smt_{k} = \text{maximum steam generation, } lb_{\text{steam}/h} \text{ or } lb/\text{gross output, for EGU } k, \text{ and} \\
Cfm_{k} = \text{conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{\text{steam}} \text{ or } MWh/lb_{\text{steam}}) from EGU } k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

\[
W_{\text{AIR}} = \frac{\sum_{i=1}^{p} \left[ \left( \frac{\text{Her}_{i}}{\text{Rm}_{i}} \right) \times \left( \frac{\text{Rm}_{i}}{\text{Rt}_{i}} \right) \right] \times \left( \frac{\text{Rt}_{i}}{\text{Rm}_{i}} \right) + \sum_{i=1}^{p} \left( \frac{\text{Ter}_{i}}{\text{Rt}_{i}} \right)}{\sum_{i=1}^{p} \left[ \left( \frac{\text{Her}_{i}}{\text{Rm}_{i}} \right) \times \left( \frac{\text{Rm}_{i}}{\text{Rt}_{i}} \right) \right] \times \left( \frac{\text{Rt}_{i}}{\text{Rm}_{i}} \right)} \quad (Eq. 2a)
\]

Where:
\[
\begin{align*}
\text{Her}_{i} &= \text{hourly emission rate (e.g., } lb/MMBtu, lb/MWh) \text{ from unit } i\text{'s CEMS for the preceding 30-group boiler operating days}, \\
\text{Rm}_{i} &= \text{hourly heat input or gross output from unit } i \text{ for the preceding 30-group boiler operating days}, \\
p &= \text{number of EGU}s in emissions averaging group that rely on CEMS or sorbent trap monitoring, \\
n &= \text{number of hours that hourly rates are collected over 30-group boiler operating days}, \\
\text{Ter}_{i} &= \text{Emissions rate from most recent emissions test of unit } i \text{ in terms of lb/heat input or lb/gross output}, \\
\text{Rt}_{i} &= \text{Total heat input or gross output of unit } i \text{ for the preceding 30-boiler operating days, and} \\
m &= \text{number of EGU}s in emissions averaging group that rely on emissions testing.}
\end{align*}
\]

\[
W_{\text{AIR}} = \frac{\sum_{i=1}^{m} \left[ \left( \frac{\text{Her}_{i}}{\text{Sm}_{i}} \times \text{Cfm}_{i} \right) \times \left( \frac{\text{Sm}_{i}}{\text{St}_{i}} \times \text{Cft}_{i} \right) \right] \times \left( \frac{\text{St}_{i}}{\text{Cft}_{i}} \right)}{\sum_{i=1}^{m} \left[ \left( \frac{\text{Her}_{i}}{\text{Sm}_{i}} \times \text{Cfm}_{i} \right) \times \left( \frac{\text{Sm}_{i}}{\text{St}_{i}} \times \text{Cft}_{i} \right) \right] \times \left( \frac{\text{St}_{i}}{\text{Cft}_{i}} \right)} \quad (Eq. 2b)
\]

Where:
\[
\begin{align*}
\text{variables with similar names share the descriptions for Equation 2a of this section,} \\
\text{Sm}_{i} &= \text{steam generation in units of pounds from unit } i \text{ that uses CEMS for the preceding 30-group boiler operating days}, \\
\text{Cfm}_{i} &= \text{conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit } i \text{ that uses CEMS from the preceding 30 group boiler operating days,} \\
\text{St}_{i} &= \text{steam generation in units of pounds from unit } i \text{ that uses emissions testing, and} \\
\text{Cft}_{i} &= \text{conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit } i \text{ that uses emissions testing.}
\end{align*}
\]
(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

\[
W_{AER} = \frac{\sum_{i=1}^{p} \left[ \frac{\sum_{d=1}^{n} (H_{ri} \times R_{mi})}{\sum_{d=1}^{n} R_{ti}} \right] + \sum_{i=1}^{m} \left[ \frac{\sum_{d=1}^{n} (T_{eri} \times R_{ti})}{\sum_{d=1}^{n} R_{ti}} \right]}{\sum_{i=1}^{p} \left[ \frac{\sum_{d=1}^{n} (H_{ri} \times R_{mi})}{\sum_{d=1}^{n} R_{ti}} \right] + \sum_{i=1}^{m} \left[ \frac{\sum_{d=1}^{n} (T_{eri} \times R_{ti})}{\sum_{d=1}^{n} R_{ti}} \right]}
\] (Eq. 3c)

Where:

\(H_{ri}\) = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

\(R_{mi}\) = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

\(p\) = number of EGUs in emissions averaging group that rely on CEMS,

\(n\) = number of hours that hourly rates are collected over the 90-group boiler operating days,

\(T_{eri}\) = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

\(R_{ti}\) = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

\(m\) = number of EGUs in emissions averaging group that rely on emissions testing.

\[
W_{AER} = \frac{\sum_{i=1}^{p} \left[ \frac{\sum_{d=1}^{n} (H_{ri} \times S_{mi} \times C_{fm_{i}})}{\sum_{d=1}^{n} S_{ti} \times C_{ft_{i}}} \right] + \sum_{i=1}^{m} \left[ \frac{\sum_{d=1}^{n} (T_{eri} \times S_{ti} \times C_{ft_{i}})}{\sum_{d=1}^{n} S_{ti} \times C_{ft_{i}}} \right]}{\sum_{i=1}^{p} \left[ \frac{\sum_{d=1}^{n} (H_{ri} \times S_{mi} \times C_{fm_{i}})}{\sum_{d=1}^{n} S_{ti} \times C_{ft_{i}}} \right] + \sum_{i=1}^{m} \left[ \frac{\sum_{d=1}^{n} (T_{eri} \times S_{ti} \times C_{ft_{i}})}{\sum_{d=1}^{n} S_{ti} \times C_{ft_{i}}} \right]}
\] (Eq. 3d)

Where:

variables with similar names share the descriptions for Equation 2a of this section,

\(S_{mi}\) = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

\(C_{fm_{i}}\) = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

\(S_{ti}\) = steam generation in units of pounds from unit i that uses emissions testing, and

\(C_{ft_{i}}\) = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(c) Separate stack requirements. For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO\(_2\), HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or
(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) CEMS (or sorbent trap monitoring) use. If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) Emissions testing. If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) Emissions averaging plan. You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:
(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO\textsubscript{2}, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in §63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) Common stack requirements. For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in §63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.
(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.


§63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) Single unit-single stack configurations. For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) Unit(s) utilizing common stack with non-affected unit(s). (i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack. If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

(5) Unit with a common control device with multiple stack or duct configuration. If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are
discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(b) Unit with multiple parallel control devices with multiple stacks. If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O₂) or carbon dioxide (CO₂) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O₂ or CO₂ concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O₂ or CO₂ data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).
(f)(1) If you use an SO2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO2 emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO2 data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluent cap are available for use in the hourly SO2 emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO2 emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).
(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) 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 Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ±14 °C (320° ±25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(2) 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.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:
(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) 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.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in §63.8(d)(2). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in §63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(C) Any data recorded during periods of startup or shutdown.
(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in §63.10000(c)(2)(iii) and Table 7 to this subpart.

(l) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with §63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer’s specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.


§63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with §63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS
or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in §63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with §63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO₂ or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in §63.10005(b). In all cases, the initial 30- boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with §63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO₂ or PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with §63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in §63.10031.

(4) If you choose to use paragraph (2) of the definition of “startup” in §63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of “startup” in §63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in §63.6(g)(1), your request will be published in the FEDERAL REGISTER for notice and comment rulemaking. Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in §63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard.

(ii) Your request need not address the items contained in §63.6(g)(2).

(iii) Your request shall provide evidence of a documented manufacturer-identified safety issue.
(iv) Your request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, your request shall contain documentation that:

(A) Your EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU;

(B) You have followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) You have identified with specificity the details of your EGU manufacturer's statement of concern.

(vi) Your request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.


**Continuous Compliance Requirements**

§63.10020  How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for 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 quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. You must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.

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

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(ii) The date and time that clean fuels being combusted for the purpose of startup begins;
(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]


§63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.
(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO₂, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO₂, O₂, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

\[ \text{Boiler operating day average} = \frac{\sum_{i=1}^{n} H_{eri}}{n} \quad (\text{Eq. 8}) \]

Where:

- \( H_{eri} \) is the hourly emissions rate for hour \( i \) and \( n \) is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

\[ \text{30 boiler operating day average} = \frac{\sum_{i=1}^{n} H_{ipv_i}}{n} \quad (\text{Eq. 9}) \]

Where:

- \( H_{ipv_i} \) is the hourly parameter value for hour \( i \) and \( n \) is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and
(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of §63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in §63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NOₓ and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NOₓ and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O₂ probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NOₓ. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NOₓ optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NOₓ in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NOₓ and O₂ monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;
(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NOX in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in §63.10031(f)(5), until April 16, 2017. After April 16, 2017, report the date of all tune-ups electronically, in accordance with §63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.

(h) You must follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in §63.10031.

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

(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown.


§63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g);
(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(4) For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 to this subpart.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.


§63.10023   How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) [Reserved]

(2) Determine your operating limit as follows:

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

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

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

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

(4) If none of the steps in paragraphs (A)(1) through (3) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average \( x \) in milliamps, and the average of your corresponding three PM compliance test runs \( y \), using equation 10.
Where:

\[ X_i = \text{the PM CPMS data points for run } i \text{ of the performance test,} \]
\[ Y_i = \text{the PM emissions value (in lb/MWh) for run } i \text{ of the performance test, and} \]
\[ n = \text{the number of data points.} \]

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

\[ R = \frac{\bar{y}}{(\bar{x} - z)} \quad (\text{Eq. 11}) \]

Where:

\[ R = \text{the relative PM lb/MWh per milliamp for your PM CPMS,} \]
\[ \bar{y} = \text{the three run average PM lb/MWh,} \]
\[ \bar{x} = \text{the three run average milliamp output from your PM CPMS, and} \]
\[ z = \text{the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.} \]

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

\[ O_L = z + \left( \frac{0.75 \times L}{R} \right) \quad (\text{Eq. 12}) \]

Where:

\[ O_L = \text{the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,} \]
\[ L = \text{your source PM emissions limit in lb/MWh,} \]
\[ z = \text{your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and} \]
\[ R = \text{the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.} \]

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.
Where:

\[ O_h = \frac{1}{n} \sum_{i=1}^{n} X_i \]  

[Eq. 13]

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

\( n \) = the number of data points, and

\( O_h \) = your site specific operating limit, in milliamps.

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

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instrument’s primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013; 81 FR 20187, Apr. 6, 2016]

Notification, Reports, and Records

§63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable.
(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10005(h)(1)(i), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(1) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(2) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(3) Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits;

(4) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your request; and

(5) You maintain records of all information regarding your choice of emission limits.
(B) You begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(D) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in §63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of “startup” in §63.10042 to paragraph (2) of the definition of “startup” (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of “startup” relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your submission;
(D) You maintain records of all information regarding your choice of the definition of "startup"; and

(E) You begin to use the revised definition of "startup" in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in §63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.


§63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 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 §63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §63.10021(e)(6) and (7) were completed.
(5) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of §63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of §63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with §63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) On or after April 16, 2017, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/tn/Chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The
electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) On or after April 16, 2017, within 60 days after the date of completing each CEMS (SO₂, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Owners or operators shall submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in this chapter.

(2) On or after April 16, 2017, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO₂ CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).

(4) On or after April 16, 2017, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) Prior to April 16, 2017, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

(i) The facility name, physical address, mailing address (if different from the physical address), and county;

(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;
(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the
stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report
the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of
this chapter;

(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under §63.10009,
indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

(vi) The identification of each emission point to which the report applies. An “emission point” is a point at which
source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified
in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an
emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan
(e.g., “Unit 2 stack,” “common stack CS001,” or “multiple stack MS001”);

(vii) The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

(viii) The pollutant(s) being addressed in the report;

(ix) The reporting period being covered by the report (if applicable);

(x) The relevant test method that was performed for a performance test (if applicable);

(xi) The date the performance test was conducted (if applicable); and

(xii) The responsible official’s name, title, and phone number.

(g) If you had a malfunction during the reporting period, the compliance 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.

§63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to)
continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A
and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation
supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you
submitted, according to the requirements in §63.10(b)(2)(xiv).

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

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

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

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

(3) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).
(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

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

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

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

(e) If you elect to average emissions consistent with §63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022.

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of “startup” in §63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum possible clean fuel capacity for each EGU;

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in §63.10020(e).

(g) You must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.
§63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.10041 Who implements and enforces this subpart?

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

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.9991(a) and (b) under §63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of “test method” in §63.2).

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

§63.10042 What definitions apply to this subpart?

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

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

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

Boiler operating day means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup periods or shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I (“Subpart I—Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel”).

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered “coal” for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of “fossil fuel-fired” or stationary, integrated gasification combined cycle:

1. Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

2. Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

   i. For a topping-cycle cogeneration unit,

   A. Useful thermal energy not less than 5 percent of total energy output; and

   B. Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

   ii. For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.
(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

*Combined-cycle gas stationary combustion turbine* means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue.

*Continental liquid oil-fired subcategory* means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

*Default electrical load* means an electrical load equal to 5 percent of the maximum sustainable electrical output (megawatts), as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter, of an affected EGU that is in startup or shutdown mode. For monitored common stack configurations, the default electrical load is 5 percent of the combined maximum sustainable electrical load of the EGUs that are in startup or shutdown mode during an hour in which the electrical load for all operating EGUs is zero. The default electrical load is used to calculate the electrical output-based emission rate (lb/MWh or lb/GWh, as applicable) for any startup or shutdown hour in which the actual electrical load is zero. The default electrical load is not used for EGUs required to make heat input-based emission rate (lb/MMBtu or lb/TBtu, as applicable) calculations. For the purposes of this subpart, the default electrical load is not considered to be a substitute data value.

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

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

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

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

*Diluent cap* means a default CO₂ or O₂ concentration that may be used to calculate the Hg, HCl, HF, or SO₂ emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO₂ concentration is below the cap value or the measured O₂ concentration is above the cap value. The appropriate diluent cap values for EGUs are presented in §63.10007(f) and in section 6.2.1.2 of Appendix A to this subpart. For the purposes of this subpart, the diluent cap is not considered to be a substitute data value.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, “Standard Specification for Fuel Oils” (incorporated by reference, see §63.14).

*Dry flue gas desulfurization technology,* or *dry FGD,* or *spray dryer absorber* (SDA), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO₂ and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

*Dry sorbent injection* (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO₂ and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

*Electric Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.
Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO₂ in the exhaust gas stream.

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

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyors, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

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

Fluidized bed boiler, or fluidized bed combustor, or circulating fluidized boiler, or CFB means a boiler utilizing a fluidized bed combustion process.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).
Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or IGCC means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in §63.9984.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Neural network or neural net for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.
Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGU's are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

Particulate matter or PM means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, “Standard Specification for Fuel Oils” (incorporated by reference, see §63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

Startup means:

(1) Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

(2) The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its
function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

Unit designed for coal ≥8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the “unit designed for low rank virgin coal” subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or wet FGD, or wet scrubber means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO₂ and HCl.

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

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:

<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Coal-fired unit not low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>9.0E-2 lb/MWh(^1)</td>
<td>Collect a minimum of 4 dscm per run.</td>
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<tr>
<td></td>
<td>OR</td>
<td>OR</td>
<td></td>
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<tr>
<td></td>
<td>Total non-Hg HAP metals</td>
<td>6.0E-2 lb/GWh</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Individual HAP metals:</td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Arsenic (As)</td>
<td>3.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Beryllium (Be)</td>
<td>6.0E-4 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cadmium (Cd)</td>
<td>4.0E-4 lb/GWh</td>
<td></td>
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<tr>
<td></td>
<td>Chromium (Cr)</td>
<td>7.0E-3 lb/GWh</td>
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<tr>
<td></td>
<td>Cobalt (Co)</td>
<td>2.0E-3 lb/GWh</td>
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<tr>
<td></td>
<td>Lead (Pb)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manganese (Mn)</td>
<td>4.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nickel (Ni)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Selenium (Se)</td>
<td>5.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen chloride (HCl)</td>
<td>1.0E-2 lb/MWh</td>
<td>For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348-03² or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sulfur dioxide (SO(_2))(^2)</td>
<td>1.0 lb/MWh</td>
<td>SO(_2) CEMS.</td>
</tr>
<tr>
<td></td>
<td>c. Mercury (Hg)</td>
<td>3.0E-3 lb/GWh</td>
<td>Hg CEMS or sorbent trap monitoring system only.</td>
</tr>
<tr>
<td>2. Coal-fired units low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>9.0E-2 lb/MWh(^1)</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total non-Hg HAP metals</td>
<td>6.0E-2 lb/GWh</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td>If your EGU is in this subcategory . . .</td>
<td>For the following pollutants . . .</td>
<td>You must meet the following emission limits and work practice standards . . .</td>
<td>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>-------------------------------------</td>
<td>---------------------------------------------------------------</td>
<td>------------------------------------------------------------------</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>3.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>6.0E-4 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>4.0E-4 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>7.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>4.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>5.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>1.0E-2 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348-032 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulfur dioxide (SO₂)³</td>
<td>1.0 lb/MWh</td>
<td>SO₂ CEMS.</td>
<td></td>
</tr>
<tr>
<td>c. Mercury (Hg)</td>
<td>4.0E-2 lb/GWh</td>
<td>Hg CEMS or sorbent trap monitoring system only.</td>
<td></td>
</tr>
<tr>
<td>3. IGCC unit</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Filterable particulate matter (PM)</td>
<td>7.0E-2 lb/MWh⁴</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>9.0E-2 lb/MWh⁵</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total non-Hg HAP metals</td>
<td>4.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>1.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>4.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
--- | --- | --- | --- |
|  |  |  |  |
| Lead (Pb) | 9.0E-3 lb/GWh |  |  |
| Manganese (Mn) | 2.0E-2 lb/GWh |  |  |
| Nickel (Ni) | 7.0E-2 lb/GWh |  |  |
| Selenium (Se) | 3.0E-1 lb/GWh |  |  |
| b. Hydrogen chloride (HCl) | 2.0E-3 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-032 or Method 320, sample for a minimum of 1 hour. |  |
| OR |  |  |  |
| Sulfur dioxide (SO$_2$)$^3$ | 4.0E-1 lb/MWh | SO$_2$ CEMS. |  |
| c. Mercury (Hg) | 3.0E-3 lb/GWh | Hg CEMS or sorbent trap monitoring system only. |  |
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units) |  |  |  |
<p>| a. Filterable particulate matter (PM) | 3.0E-1 lb/MWh$^1$ | Collect a minimum of 1 dscm per run. |  |
| OR |  |  |  |
| OR |  |  |  |
| Total HAP metals | 2.0E-4 lb/MWh | Collect a minimum of 2 dscm per run. |  |
| OR |  |  |  |
| OR |  |  |  |
| Individual HAP metals: |  | Collect a minimum of 2 dscm per run. |  |
| Antimony (Sb) | 1.0E-2 lb/GWh |  |  |
| Arsenic (As) | 3.0E-3 lb/GWh |  |  |
| Beryllium (Be) | 5.0E-4 lb/GWh |  |  |
| Cadmium (Cd) | 2.0E-4 lb/GWh |  |  |
| Chromium (Cr) | 2.0E-2 lb/GWh |  |  |
| Cobalt (Co) | 3.0E-2 lb/GWh |  |  |
| Lead (Pb) | 8.0E-3 lb/GWh |  |  |
| Manganese (Mn) | 2.0E-2 lb/GWh |  |  |
| Nickel (Ni) | 9.0E-2 lb/GWh |  |  |
| Selenium (Se) | 2.0E-2 lb/GWh |  |  |
| Mercury (Hg) | 1.0E-4 lb/GWh | For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be &lt; 1/2 the standard. |  |</p>
<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>b. Hydrogen chloride (HCl)</td>
<td>4.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td></td>
<td>c. Hydrogen fluoride (HF)</td>
<td>4.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)</td>
<td>a. Filterable particulate matter (PM)</td>
<td>2.0E-1 lb/MWh(^1)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total HAP metals</td>
<td>7.0E-3 lb/MWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Individual HAP metals:</td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Arsenic (As)</td>
<td>6.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Beryllium (Be)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cadmium (Cd)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Chromium (Cr)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cobalt (Co)</td>
<td>3.0E-1 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lead (Pb)</td>
<td>3.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manganese (Mn)</td>
<td>1.0E-1 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nickel (Ni)</td>
<td>4.1E0 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Selenium (Se)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mercury (Hg)</td>
<td>4.0E-4 lb/GWh</td>
<td>For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be &lt; 1/2 the standard.</td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-3 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td></td>
<td>c. Hydrogen fluoride (HF)</td>
<td>5.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>6. Solid oil-derived fuel-fired unit</td>
<td>a. Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MWh(^1)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
---|---|---|---|
OR | Total non-Hg HAP metals | 6.0E-1 lb/GWh | Collect a minimum of 1 dscm per run. |
| OR | Individual HAP metals: | | |
| Antimony (Sb) | 8.0E-3 lb/GWh | | |
| Arsenic (As) | 3.0E-3 lb/GWh | | |
| Beryllium (Be) | 6.0E-4 lb/GWh | | |
| Cadmium (Cd) | 7.0E-4 lb/GWh | | |
| Chromium (Cr) | 6.0E-3 lb/GWh | | |
| Cobalt (Co) | 2.0E-3 lb/GWh | | |
| Lead (Pb) | 2.0E-2 lb/GWh | | |
| Manganese (Mn) | 7.0E-3 lb/GWh | | |
| Nickel (Ni) | 4.0E-2 lb/GWh | | |
| Selenium (Se) | 6.0E-3 lb/GWh | | |
| b. Hydrogen chloride (HCl) | 4.0E-4 lb/MWh | For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour. |
| OR | Sulfur dioxide (SO₂)² | 1.0 lb/MWh | SO₂ CEMS. |
| c. Mercury (Hg) | 2.0E-3 lb/GWh | Hg CEMS or Sorbent trap monitoring system only. |

1 Gross output.
2 Incorporated by reference, see §63.14.
3 You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO₂ CEMS installed.
4 Duct burners on syngas; gross output.
5 Duct burners on natural gas; gross output.

[81 FR 20190, Apr. 6, 2016]
Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:1

<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Coal-fired unit not low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh²</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR OR</td>
<td>Total non-Hg HAP metals</td>
<td>5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR OR</td>
<td>Individual HAP metals</td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td></td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td></td>
<td>1.1E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td></td>
<td>2.0E-1 lb/TBtu or 2.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td></td>
<td>3.0E-1 lb/TBtu or 3.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td></td>
<td>2.8E0 lb/TBtu or 3.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td></td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td></td>
<td>1.2E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td></td>
<td>4.0E0 lb/TBtu or 5.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td></td>
<td>3.5E0 lb/TBtu or 4.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td></td>
<td>5.0E0 lb/TBtu or 6.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td></td>
<td>2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh</td>
<td>For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>OR OR</td>
<td>Sulfur dioxide (SO₂)</td>
<td>2.0E-1 lb/MMBtu or 1.5E0 lb/MWh</td>
<td>SO₂ CEMS.</td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . .

<table>
<thead>
<tr>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>c. Mercury (Hg)</td>
<td>1.2E0 lb/TBtu or 1.3E-2 lb/GWh</td>
<td>LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1.0E0 lb/TBtu or 1.1E-2 lb/GWh</td>
<td>LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.</td>
</tr>
<tr>
<td>2. Coal-fired unit low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total non-Hg HAP metals</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Individual HAP metals:</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Antimony (Sb)</td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Arsenic (As)</td>
<td>1.1E0 lb/TBtu or 2.0E-2 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Beryllium (Be)</td>
<td>2.0E-1 lb/TBtu or 2.0E-3 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Cadmium (Cd)</td>
<td>3.0E-1 lb/TBtu or 3.0E-3 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Chromium (Cr)</td>
<td>2.8E0 lb/TBtu or 3.0E-2 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Cobalt (Co)</td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Lead (Pb)</td>
<td>1.2E0 lb/TBtu or 2.0E-2 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Manganese (Mn)</td>
<td>4.0E0 lb/TBtu or 5.0E-2 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Nickel (Ni)</td>
<td>3.5E0 lb/TBtu or 4.0E-2 lb/GWh</td>
</tr>
<tr>
<td></td>
<td>Selenium (Se)</td>
<td>5.0E0 lb/TBtu or 6.0E-2 lb/GWh</td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
---|---|---|---|
| b. Hydrogen chloride (HCl) | 2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh | For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-033 or Method 320, sample for a minimum of 1 hour. |
| OR | | | |
| Sulfur dioxide (SO₂)⁴ | 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh | SO₂ CEMS. |
| c. Mercury (Hg) | 4.0E0 lb/TBtu or 4.0E-2 lb/GWh | LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only. |
3. IGCC unit | a. Filterable particulate matter (PM) | 4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh² | Collect a minimum of 1 dscm per run. |
| OR | | | |
| OR | | | |
| Total non-Hg HAP metals | 6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh | Collect a minimum of 1 dscm per run. |
| OR | | | |
| OR | | | |
| Individual HAP metals: | | | |
| Antimony (Sb) | 1.4E0 lb/TBtu or 2.0E-2 lb/GWh | Collect a minimum of 2 dscm per run. |
| Arsenic (As) | 1.5E0 lb/TBtu or 2.0E-2 lb/GWh | | |
| Beryllium (Be) | 1.0E-1 lb/TBtu or 1.0E-3 lb/GWh | | |
| Cadmium (Cd) | 1.5E-1 lb/TBtu or 2.0E-3 lb/GWh | | |
| Chromium (Cr) | 2.9E0 lb/TBtu or 3.0E-2 lb/GWh | | |
| Cobalt (Co) | 1.2E0 lb/TBtu or 2.0E-2 lb/GWh | | |
| Lead (Pb) | 1.9E+2 lb/TBtu or 1.8E0 lb/GWh | | |
| Manganese (Mn) | 2.5E0 lb/TBtu or 3.0E-2 lb/GWh | | |
| Nickel (Ni) | 6.5E0 lb/TBtu or 7.0E-2 lb/GWh | | |
| Selenium (Se) | 2.2E+1 lb/TBtu or 3.0E-1 lb/GWh | | |
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .  
--- | --- | --- | ---  
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units) | b. Hydrogen chloride (HCl) | 5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.  
 | c. Mercury (Hg) | 2.5E0 lb/TBtu or 3.0E-2 lb/GWh | LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.  
 | a. Filterable particulate matter (PM) | 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh² | Collect a minimum of 1 dscm per run.  
 | OR | OR | |  
 | Total HAP metals | 8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh | Collect a minimum of 1 dscm per run.  
 | OR | OR | |  
 | Individual HAP metals: | | Collect a minimum of 1 dscm per run.  
 | Antimony (Sb) | 1.3E+1 lb/TBtu or 2.0E-1 lb/GWh |  
 | Arsenic (As) | 2.8E0 lb/TBtu or 3.0E-2 lb/GWh |  
 | Beryllium (Be) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh |  
 | Cadmium (Cd) | 3.0E-1 lb/TBtu or 2.0E-3 lb/GWh |  
 | Chromium (Cr) | 5.5E0 lb/TBtu or 6.0E-2 lb/GWh |  
 | Cobalt (Co) | 2.1E+1 lb/TBtu or 3.0E-1 lb/GWh |  
 | Lead (Pb) | 8.1E0 lb/TBtu or 8.0E-2 lb/GWh |  
 | Manganese (Mn) | 2.2E+1 lb/TBtu or 3.0E-1 lb/GWh |  
 | Nickel (Ni) | 1.1E+2 lb/TBtu or 1.1E0 lb/GWh |  
 | Selenium (Se) | 3.3E0 lb/TBtu or 4.0E-2 lb/GWh |  
 | Mercury (Hg) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh | For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
If your EGU is in this subcategory...

For the following pollutants...

You must meet the following emission limits and work practice standards...

Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart...

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit</th>
<th>Sampling Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen chloride (HCl)</td>
<td>2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03^3 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>Hydrogen fluoride (HF)</td>
<td>4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03^3 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh^2</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>Total HAP metals</td>
<td>6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>Individual HAP metals</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>2.2E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>4.3E0 lb/TBtu or 8.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>6.0E-1 lb/TBtu or 3.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>3.0E-1 lb/TBtu or 3.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>3.1E+1 lb/TBtu or 3.0E-1 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>1.1E+2 lb/TBtu or 1.4E0 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>4.9E0 lb/TBtu or 8.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>2.0E+1 lb/TBtu or 3.0E-1 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>4.7E+2 lb/TBtu or 4.1E0 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>9.8E0 lb/TBtu or 2.0E-1 lb/GWh</td>
<td></td>
</tr>
<tr>
<td>Mercury (Hg)</td>
<td>4.0E-2 lb/TBtu or 4.0E-4 lb/GWh</td>
<td>For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be &lt; 1/2 the standard.</td>
</tr>
<tr>
<td>If your EGU is in this subcategory . . .</td>
<td>For the following pollutants . . .</td>
<td>You must meet the following emission limits and work practice standards . . .</td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>-----------------------------------</td>
<td>-------------------------------------------------</td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 2 hours.</td>
</tr>
<tr>
<td>c. Hydrogen fluoride (HF)</td>
<td>6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 2 hours.</td>
</tr>
</tbody>
</table>

6. Solid oil-derived fuel-fired unit

| a. Filterable particulate matter (PM) | 8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh² | Collect a minimum of 1 dscm per run. |

OR

OR

Total non-Hg HAP metals

| 4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh | Collect a minimum of 1 dscm per run. |

OR

OR

Individual HAP metals:

| Antimony (Sb) | 8.0E-1 lb/TBtu or 7.0E-3 lb/GWh |
| Arsenic (As) | 3.0E-1 lb/TBtu or 5.0E-3 lb/GWh |
| Beryllium (Be) | 6.0E-2 lb/TBtu or 5.0E-4 lb/GWh |
| Cadmium (Cd) | 3.0E-1 lb/TBtu or 4.0E-3 lb/GWh |
| Chromium (Cr) | 8.0E-1 lb/TBtu or 2.0E-2 lb/GWh |
| Cobalt (Co) | 1.1E0 lb/TBtu or 2.0E-2 lb/GWh |
| Lead (Pb) | 8.0E-1 lb/TBtu or 2.0E-2 lb/GWh |
| Manganese (Mn) | 2.3E0 lb/TBtu or 4.0E-2 lb/GWh |
| Nickel (Ni) | 9.0E0 lb/TBtu or 2.0E-1 lb/GWh |
| Selenium (Se) | 1.2E0 lb/Tbtu or 2.0E-2 lb/GWh |
| b. Hydrogen chloride (HCl) | 5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh² | For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour. |

OR
If your EGU is in this subcategory . . . & For the following pollutants . . . & You must meet the following emission limits and work practice standards . . . & Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .

| Sulfur dioxide (SO$_2$) & 3.0E-1 lb/MMBtu or 2.0E0 lb/MWh & SO$_2$ CEMS. |
|-------------------------|------------------------|----------------|
| c. Mercury (Hg) & 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh & LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only. |

1For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

2Gross output.

3Incorporated by reference, see §63.14.

4You may not use the alternate SO$_2$ limit if your EGU does not have some form of FGD system and SO$_2$ CEMS installed.

[81 FR 20192, Apr. 6, 2016]

**Table 3 to Subpart UUUUU of Part 63—Work Practice Standards**

As stated in §§63.9991, you must comply with the following applicable work practice standards:

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

[72x737]40 CFR 63, Subpart UUUUU (5U) Page 63 of 105 Attachment E TV No. 147-40656-00020
<table>
<thead>
<tr>
<th>If your EGU is . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2) If you choose to comply using paragraph (2) of the definition of “startup” in §63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.</td>
<td>For startup of an EGU, you must use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in §63.10020(e).</td>
</tr>
<tr>
<td>Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.</td>
<td>You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.</td>
</tr>
<tr>
<td>b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
<td>b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
</tr>
<tr>
<td>c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.</td>
<td>c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.</td>
</tr>
<tr>
<td>d. You must collect monitoring data during startup periods, as specified in §63.10020(a) and (e). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.</td>
<td>d. You must collect monitoring data during startup periods, as specified in §63.10020(a) and (e). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.</td>
</tr>
<tr>
<td>4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices.</td>
<td>If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.</td>
</tr>
<tr>
<td>Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
<td>Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
</tr>
</tbody>
</table>
If your EGU is . . .

You must meet the following . . .

You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in §63.10020(a). You must keep records during shutdown periods, as provided in §§63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

As stated in §63.9991, you must comply with the applicable operating limits:

<table>
<thead>
<tr>
<th>If you demonstrate compliance using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM CPMS</td>
<td>Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of §63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).</td>
</tr>
</tbody>
</table>

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

As stated in §63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>Using . . .</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Filterable Particulate matter (PM)</td>
<td>Emissions Testing</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at appendix A-1 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
</tr>
<tr>
<td>To conduct a performance test for the following pollutant . . .</td>
<td>Using . . .</td>
<td>You must perform the following activities, as applicable to your input- or output-based emission limit . . .</td>
<td>Using . . .²</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>e. Measure the filterable PM concentration</td>
<td>Method 5 at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160° ± 14 °C (320° ± 25 °F).</td>
<td></td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

OR

<table>
<thead>
<tr>
<th>PM CEMS</th>
<th>a. Install, certify, operate, and maintain the PM CEMS</th>
<th>Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
<td></td>
</tr>
<tr>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
</tr>
</tbody>
</table>

2. Total or individual non-Hg HAP metals Emissions Testing

<table>
<thead>
<tr>
<th>a. Select sampling ports location and the number of traverse points.</th>
<th>Method 1 at appendix A-1 to part 60 of this chapter.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.³</td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
</tr>
<tr>
<td>e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration</td>
<td>Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.</td>
</tr>
<tr>
<td>f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
</tr>
</tbody>
</table>
To conduct a performance test for the following pollutant . . .

<table>
<thead>
<tr>
<th>Emissions Testing</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . .</th>
<th>Using . . .^2</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)</td>
<td>a. Select sampling ports location and the number of traverse points.</td>
<td>Method 1 at appendix A-1 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.3</td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>e. Measure the HCl and HF emissions concentrations</td>
<td>Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM 6348-03^3 with (1) the following conditions when using ASTM D6348-03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and</td>
</tr>
</tbody>
</table>

3.e.1(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

\[
\text{Reported Result} = \frac{\text{(Measured Concentration in Stack)}}{\%R} \times 10^6
\]

and

To conduct a performance test for the following pollutant . . . (cont'd)

<table>
<thead>
<tr>
<th>Using . . . (cont'd)</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)</th>
<th>Using . . .^2 (cont'd)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.</td>
<td></td>
</tr>
</tbody>
</table>
To conduct a performance test for the following pollutant . . . (cont'd) | Using . . . (cont'd) | You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd) | Using . . . ^2 (cont'd)
--- | --- | --- | ---
f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates | Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

OR

OR

HCl and/or HF CEMS | a. Install, certify, operate, and maintain the HCl or HF CEMS | Appendix B of this subpart.

b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems | Part 75 of this chapter and §63.10010(a), (b), (c), and (d).

c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates | Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

4. Mercury (Hg)

Emissions Testing | a. Select sampling ports location and the number of traverse points | Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.

b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.

c. Determine oxygen and carbon dioxide concentrations of the stack gas | Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.3

d. Measure the moisture content of the stack gas | Method 4 at appendix A-3 to part 60 of this chapter.

e. Measure the Hg emission concentration | Method 30B at appendix A-8 to part 60 of this chapter. ASTM D6784.3 or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.

f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates | Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

OR

OR

Hg CEMS | a. Install, certify, operate, and maintain the CEMS | Sections 3.2.1 and 5.1 of appendix A of this subpart.

b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems | Part 75 of this chapter and §63.10010(a), (b), (c), and (d).
To conduct a performance test for the following pollutant . . . (cont’d) | Using . . . (cont’d) | You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont’d) | Using . . . ² (cont’d)
---|---|---|---
c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates

OR

Sorbent trap monitoring system

a. Install, certify, operate, and maintain the sorbent trap monitoring system

Sections 3.2.2 and 5.2 of appendix A to this subpart.

b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems

Part 75 of this chapter and §63.10010(a), (b), (c), and (d).

c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates

Section 6 of appendix A to this subpart.

OR

LEE testing

a. Select sampling ports location and the number of traverse points

Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.

b. Determine velocity and volumetric flow-rate of the stack gas

Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.

c. Determine oxygen and carbon dioxide concentrations of the stack gas

Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981, or diluent gas monitoring systems certified according to part 75 of this chapter.

d. Measure the moisture content of the stack gas

Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.

e. Measure the Hg emission concentration

Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (i.e., per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.

f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates

Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).
To conduct a performance test for the following pollutant . . . (cont'd)

<table>
<thead>
<tr>
<th>Using . . . (cont'd)</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)</th>
<th>Using . . . ² (cont'd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold</td>
<td>Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.</td>
<td></td>
</tr>
</tbody>
</table>

5. Sulfur dioxide (SO₂) SO₂ CEMS

<table>
<thead>
<tr>
<th>a. Install, certify, operate, and maintain the CEMS</th>
<th>Part 75 of this chapter and §63.10010(a) and (f).</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
</tr>
<tr>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
</tr>
</tbody>
</table>

¹Regarding emissions data collected during periods of startup or shutdown, see §§63.10020(b) and (c) and 63.10021(h).

²See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

³Incorporated by reference, see §63.14.

[81 FR 20197, Apr. 6, 2016]

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

As stated in §63.10007, you must comply with the following requirements for establishing operating limits:

<table>
<thead>
<tr>
<th>If you have an applicable emission limit for . . .</th>
<th>And you choose to establish PM CPMS operating limits, you must . . .</th>
<th>And . . .</th>
<th>Using . . .</th>
<th>According to the following procedures . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU</td>
<td>Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to §63.10010(h)(1)</td>
<td>Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal)</td>
<td>Data from the PM CPMS and the PM or HAP metals performance tests</td>
<td>1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of §63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.</td>
</tr>
</tbody>
</table>
### Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in §63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

<table>
<thead>
<tr>
<th>If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .</th>
<th>You demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. CEMS to measure filterable PM, SO\textsubscript{2}, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg</td>
<td>Calculating the 30- (or 90-) boiler operating day rolling average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.</td>
</tr>
<tr>
<td>2. PM CPMS to measure compliance with a parametric operating limit</td>
<td>Calculating the 30- (or 90-) boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.</td>
</tr>
<tr>
<td>3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring</td>
<td>If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.</td>
</tr>
<tr>
<td>4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2</td>
<td>Calculating the results of the testing in units of the applicable emissions standard.</td>
</tr>
<tr>
<td>5. Conducting periodic performance tune-ups of your EGU(s)</td>
<td>Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).</td>
</tr>
<tr>
<td>6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup</td>
<td>Operating in accordance with Table 3.</td>
</tr>
<tr>
<td>7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown</td>
<td>Operating in accordance with Table 3.</td>
</tr>
</tbody>
</table>

### Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

As stated in §63.10031, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>You must submit a</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.10031(c)(1) through (9); and</td>
<td>Semiannually according to the requirements in §63.10031(b).</td>
</tr>
</tbody>
</table>
You must submit a | The report must contain . . . | You must submit the report . . .  
--- | --- | ---  
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 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, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and  

c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.10031(e).  

Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU  
As stated in §63.10040, you must comply with the applicable General Provisions according to the following:

<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Applies to subpart UUUUU</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>Applicability</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes. Additional terms defined in §63.10042.</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and Abbreviations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited Activities and Circumvention</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.5</td>
<td>Preconstruction Review and Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j)</td>
<td>Compliance with Standards and Maintenance Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(e)(1)(i)</td>
<td>General Duty to minimize emissions</td>
<td>No. See §63.10000(b) for general duty requirement.</td>
</tr>
<tr>
<td>§63.6(e)(1)(ii)</td>
<td>Requirement to correct malfunctions ASAP</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(e)(3)</td>
<td>SSM Plan requirements</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>SSM exemption</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(1)</td>
<td>SSM exemption</td>
<td>No.</td>
</tr>
</tbody>
</table>

[81 FR 20201, Apr. 6, 2016]
<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Applies to subpart UUUUU</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.6(g)</td>
<td>Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard</td>
<td>Yes. See §§63.10011(g)(4) and 63.10021(h)(4) for additional requirements.</td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Performance testing</td>
<td>No. See §63.10007.</td>
</tr>
<tr>
<td>§63.8</td>
<td>Monitoring Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>General duty to minimize emissions and CMS operation</td>
<td>No. See §63.10000(b) for general duty requirement.</td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Requirement to develop SSM Plan for CMS</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(d)(3)</td>
<td>Written procedures for CMS</td>
<td>Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.</td>
</tr>
<tr>
<td>§63.9</td>
<td>Notification Requirements</td>
<td>Yes, except (1) for the 60-day notification prior to conducting a performance test in §63.9(e); instead use a 30-day notification period per §63.10030(d), (2) the notification of the CMS performance evaluation in §63.9(g)(1) is limited to RATAs, and (3) the information required per §63.9(h)(2)(i); instead provide the information required per §63.10030(e)(1) through (e)(6) and (e)(8).</td>
</tr>
<tr>
<td>§63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)</td>
<td>Recordkeeping and Reporting Requirements</td>
<td>Yes, except for the requirements to submit written reports under §63.10(e)(3)(v).</td>
</tr>
<tr>
<td>§63.10(b)(2)(i)</td>
<td>Recordkeeping of occurrence and duration of startups and shutdowns</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(ii)</td>
<td>Recordkeeping of malfunctions</td>
<td>No. See §63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iii)</td>
<td>Maintenance records</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iv)</td>
<td>Actions taken to minimize emissions during SSM</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(v)</td>
<td>Actions taken to minimize emissions during SSM</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vi)</td>
<td>Recordkeeping for CMS malfunctions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vii) through (ix)</td>
<td>Other CMS requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(3) and (d)(3) through (5)</td>
<td>Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions</td>
<td>Yes.</td>
</tr>
</tbody>
</table>
Applicability. These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

Initial Certification and Recertification Procedures. The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

Quality Assurance and Quality Control Requirements. The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.
1.4 Missing Data Procedures. The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 Monitoring System Installation Requirements. Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, §63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 Primary and Backup Monitoring Systems. In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, i.e., when the system is “in control”. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 Redundant Backup Systems. A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on “hot standby” in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 Non-redundant Backup Monitoring Systems. A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on “cold standby” and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 Temporary Like-kind Replacement Analyzers. When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix “LK”.

2.2.4 Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers. To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.
2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg\textsuperscript{0}, CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 Definitions.

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg\textsuperscript{+2} to Hg\textsuperscript{0} converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl\textsubscript{2}), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.
3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit or RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 *Quality Assurance (QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.
3.2.1.1 Equipment Specifications.

3.2.1.1.1 Materials of Construction. All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 Temperature Considerations. All system components prior to the Hg$^{2+}$ to Hg$^0$ converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 Measurement System Components.

3.2.1.1.3.1 Sample Probe. The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 Filter or Other Particulate Removal Device. The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 Sample Line. The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 Conditioning Equipment. For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 Sampling Pump. A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 Equipment Specifications.
3.2.1.3.6 Calibration Gas System(s). Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl₂ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.3.7 Sample Gas Delivery. The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.3.8 Hg Analyzer. An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.3.9 Data Recorder. A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 Reagents and Standards.

3.2.1.2.1 NIST Traceability. Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg⁰ and HgCl₂ are required. Special reagents and equipment may be needed to prepare the Hg⁰ and HgCl₂ gas standards (e.g., NIST-traceable solutions of HgCl₂ and gas generators equipped with mass flow controllers).

3.2.1.2.2 Required Calibration Gas Concentrations.

3.2.1.2.2.1 Zero-Level Gas. A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 Low-Level Gas. A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 Mid-Level Gas. A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 High-Level Gas. A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 Installation and Measurement Location. For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO₂ or O₂ monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 Monitor Span and Range Requirements. Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 Maximum Potential Concentration. There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 µg/scm for all coal
ranks (including coal refuse) except for lignite; for lignite, use 16 µg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (i.e., the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 **Span Value.** To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

3.2.1.4.3 **Analyzer Range.** The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 **Sorbent Trap Monitoring System.** A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 **Other Necessary Data Collection.** To convert measured hourly Hg concentrations to the units of the applicable emissions standard (i.e., lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 **Heat Input-Based Emission Limits.** For a heat input-based Hg emission limit (i.e., in lb/TBtu), data from a certified CO₂ or O₂ monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 **Electrical Output-Based Emission Rates.** If the applicable Hg limit is electrical output-based (i.e., lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 **Sorbent Trap Monitoring System Operation.** Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 **Certification Requirements.** All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in §63.9984(f).

4.1.1 **Hg CEMS.** Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (i.e., combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 **7-Day Calibration Error Test.** Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in paragraphs...
3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in paragraphs 3.1.4 of this appendix) for the test. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. If moisture is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (i.e., resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.2 Linearity Check. Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 Three-Level System Integrity Check. Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

### Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

<table>
<thead>
<tr>
<th>For this required certification test</th>
<th>The main performance specification is</th>
<th>The alternate performance specification is</th>
<th>And the conditions of the alternate specification are</th>
</tr>
</thead>
<tbody>
<tr>
<td>7-day calibration error test²⁶</td>
<td></td>
<td></td>
<td>The alternate specification may be used on any day of the test.</td>
</tr>
<tr>
<td>Linearity check³⁶</td>
<td></td>
<td></td>
<td>The alternate specification may be used at any gas level.</td>
</tr>
<tr>
<td>3-level system integrity check⁴</td>
<td></td>
<td></td>
<td>The alternate specification may be used at any gas level.</td>
</tr>
<tr>
<td>RATA</td>
<td>20.0% RA</td>
<td></td>
<td>RMₐvg &lt; 2.5 µg/scm</td>
</tr>
</tbody>
</table>

³³ For this required certification test.

¹¹ The main performance specification is.

²² The alternate performance specification is.

⁴⁴ And the conditions of the alternate specification are.

The alternate specification may be used on any day of the test. The alternate specification may be used at any gas level. The alternate specification may be used at any gas level. RMₐvg < 2.5 µg/scm.
<table>
<thead>
<tr>
<th>For this required certification test</th>
<th>The main performance specification(^1) is . . .</th>
<th>The alternate performance specification(^1) is . . .</th>
<th>And the conditions of the alternate specification are . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cycle time test(^5)</td>
<td>15 minutes where the stability criteria are readings change by &lt; 2.0% of span or by ≤ 0.5 µg/scm, for 2 minutes.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Note that |R − A| is the absolute value of the difference between the reference gas value and the analyzer reading. |R − A\(_{avg}\)| is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

\(^2\) Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

\(^3\) Use elemental Hg standards.

\(^4\) Use oxidized Hg standards.

\(^5\) Use elemental Hg standards; a high-level upscale gas must be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitoring systems must be capable of recording at least one Hg concentration reading every 15 minutes.

\(^6\) If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

\(^7\) Note that |RM\(_{avg}\) − C\(_{avg}\)| is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; CC is the confidence coefficient from Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter.

### 4.1.1.4 Cycle Time Test

Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

### 4.1.1.5 Relative Accuracy Test Audit (RATA)

Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

\[
RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad (Eq. \ A - 1)
\]
Where:

RD = Relative Deviation between the Hg concentrations of samples “a” and “b” (percent),

C_a = Hg concentration of Hg sample “a” (µg/dscm), and

C_b = Hg concentration of Hg sample “b” (µg/dscm).

4.1.1.5.1 Special Considerations. A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 Calculation of RATA Results. Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2-6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.5.3 Bias Adjustment. Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 Sorbent Trap Monitoring Systems. For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 Reference Methods. The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 Calculation of RATA Results. Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the
reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The main and
alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring
system.

4.1.2.5 Bias Adjustment. Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems. Monitoring systems that are used to measure
stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of
a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be
certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 Recertification. Whenever the owner or operator makes a replacement, modification, or change to a certified
CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure
or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or
operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement,
modification, or change to the flue gas handling system or the unit operation that may significantly change the
concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed
for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by
the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete
monitoring system replacement, and changing the location or orientation of the sampling probe.

5. ONGOING QUALITY ASSURANCE (QA) AND DATA VALIDATION

5.1 Hg CEMS.

5.1.1 Required QA Tests. Periodic QA testing of each Hg CEMS is required following initial certification. The
required QA tests, the test frequencies, and the performance specifications that must be met are summarized in
Table A-2, below. All tests must be performed with the affected unit(s) operating (i.e., combusting fuel). Except for the
RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow
the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 Test Frequency. The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable
 elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator,
you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration
error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration
levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for
these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-
level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are
allowed for “non-QA operating quarters”. A maximum of three consecutive exemptions for this reason are permitted,
following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the
next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The
test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the
linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system
integrity checks.

5.1.2.3 Perform a single-level system integrity check weekly, i.e., once every 7 operating days (see the third column
in Table A-2 of this appendix).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, i.e., once every four QA operating
quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating
quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one
calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of
the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the
eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a
required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 Grace Periods.

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 Data Validation. The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 Conditional Data Validation. For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2—On-Going QA Test Requirements for Hg CEMS

<table>
<thead>
<tr>
<th>Perform this type of QA test</th>
<th>At this frequency</th>
<th>With these qualifications and exceptions</th>
<th>Acceptance criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calibration error test⁴</td>
<td>Daily</td>
<td>• Use either a mid- or high-level gas</td>
<td>(</td>
</tr>
<tr>
<td>Single-level system integrity check</td>
<td>Weekly¹</td>
<td>• Use oxidized Hg—either mid- or high-level</td>
<td>(</td>
</tr>
<tr>
<td>Linearity check or 3-level system integrity check</td>
<td>Quarterly³</td>
<td>• Required in each “QA operating quarter”² and no less than once every 4 calendar quarters</td>
<td>(</td>
</tr>
<tr>
<td>RATA</td>
<td>Annual⁴</td>
<td>• Test deadline may be extended for “non-QA operating quarters,” up to a maximum of 8 quarters from the quarter of the previous test.</td>
<td>(\leq 20.0% \text{ RA when } C_{\text{avg}} \geq 2.5 \mu g/\text{scm or }</td>
</tr>
</tbody>
</table>

¹“Weekly” means once every 7 operating days.

²A “QA operating quarter” is a calendar quarter with at least 168 unit or stack operating hours.
“Quarterly” means once every QA operating quarter.

“Annual” means once every four QA operating quarters.

If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

5.1.6 Adjustment of Span. If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 Sorbent Trap Monitoring Systems.

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, i.e., once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 Flow Rate, Diluent Gas, and Moisture Monitoring Systems. The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§63.10010(b) through (d)).

5.4 QA/QC Program Requirements. The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 General Requirements.

5.4.1.1 Preventive Maintenance. Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 Recordkeeping and Reporting. Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.
5.4.1.3 Maintenance Records. Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 Specific Requirements for Hg CEMS.

5.4.2.1 Daily Calibrations, Linearity Checks and System Integrity Checks. Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 Monitoring System Adjustments. Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 Relative Accuracy Test Audits. Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 Specific Requirements for Sorbent Trap Monitoring Systems.

5.4.3.1 Sorbent Trap Identification and Tracking. Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 Monitoring System Integrity and Data Quality. Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 Hg Analysis. Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 Data Collection Period. State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 Relative Accuracy Test Audit Procedures. Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with §60.13(h)(2) of this chapter.
6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (i.e., flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 Calculation of Hg Emission Rates. Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 Heat Input-Based Hg Emission Rates. Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by $6.24 \times 10^{-11}$ to convert it from $\mu g/scm$ to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average $O_2$ concentration is above 14.0% $O_2$ (19.0% for an IGCC) or the hourly average $CO_2$ concentration is below 5.0% $CO_2$ (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by $10^6$ to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term $E_{hj}$ in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 Electrical Output-Based Hg Emission Rates. Calculate electrical output-based Hg emission limits in units of lb/GWth, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h$$

(Equation A-2)

Where:

$M_h$ = Hg mass emission rate for the hour (lb/h)

$K$ = Units conversion constant, $6.24 \times 10^{-11}$ lb-scm/$\mu g$-scf,

$C_h$ = Hourly average Hg concentration, wet basis ($\mu g/scm$)

$Q_h$ = Stack gas volumetric flow rate for the hour (scfh).

(NOTE: Use unadjusted flow rate values; bias adjustment is not required)
\[ M_h = K C_h Q_h (1 - B_{ws}) \]  
(Equation A-3)

Where:

\( M_h \) = Hg mass emission rate for the hour (lb/h)

\( K \) = Units conversion constant, \( 6.24 \times 10^{-11} \) lb-scm/µg-scf.

\( C_h \) = Hourly average Hg concentration, dry basis (µg/dscm).

\( Q_h \) = Stack gas volumetric flow rate for the hour (scfh)

(Note: Use unadjusted flow rate values; bias adjustment is not required).

\( B_{ws} \) = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

\[ E_{ho} = \frac{M_h}{(MW)_h} \times 10^3 \]  
(Equation A-4)

Where:

\( E_{ho} \) = Electrical output-based Hg emission rate (lb/GWh).

\( M_h \) = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

\( (MW)_h \) = Gross electrical load for the hour, in megawatts (MW).

\( 10^3 \) = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation A-5 of this appendix to calculate the Hg emission rate for each averaging period.

\[ E_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \]  
(Eq. A – 5)

Where:

\( E_o \) = Hg emission rate for the averaging period (lb/GWh),

\( E_{ho} \) = Gross output-based hourly Hg emission rate for unit or stack sampling hour “h” in the averaging period, from Equation A-4 of this appendix (lb/GWh), and

\( n \) = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. (Note: Do not include non-operating hours with zero emission rates in the average).

7. RECORDKEEPING AND REPORTING

7.1 Recordkeeping Provisions. For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the
date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 Monitoring Plan Records. For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (i.e., flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 Updates. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 Contents of the Monitoring Plan. For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under §75.53 (g) of this chapter.

7.1.1.2.1 Electronic. The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 Hard Copy. Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 Operating Parameter Records. The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in §63.10042).

7.1.2.6 The EGUs that constitute an emissions averaging group.

7.1.3 Hg Emissions Records (Hg CEMS). For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;
7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.4 Hg Emissions Records (Sorbent Trap Monitoring Systems). For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.5 Stack Gas Volumetric Flow Rate Records.

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

7.1.6 Records of Stack Gas Moisture Content.

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:
7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from §75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

7.1.7 Records of Diluent Gas (CO₂ or O₂) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO₂ or O₂ concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO₂ or O₂ concentration records, as specified in §75.57(g) of this chapter.

7.1.8 Hg Emission Rate Records. For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.8.5 If applicable, a code to indicate that the default gross output (as defined in §63.10042) was used to calculate the Hg emission rate.

7.1.8.6 If applicable, a code to indicate that the diluent cap (as defined in §63.10042) was used to calculate the Hg emission rate.

7.1.9 Certification and Quality Assurance Test Records. For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;
7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in §75.59 of this chapter.

7.2 Reporting Requirements.

7.2.1 General Reporting Provisions. The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 Notifications. The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with §63.10030.

7.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in §63.9984. Also submit the monitoring plan information in §75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.
7.2.4 Certification, Recertification, and Quality-Assurance Test Reporting. Except for daily QA tests of the required monitoring systems (i.e., calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 Quarterly Reports.

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 Compliance Certification. Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official’s name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.


Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 Monitoring System Installation Requirements. Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with §63.10010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.
2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010)”Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy” (incorporated by reference, see §63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤R ≤130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

\[
\text{Reported Result} = \left( \frac{\text{Measured Concentration in Stack}}{\%R} \right) \times 100 \quad (\text{Eq. B-1})
\]
3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ±5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, “quarterly” means once every “QA operating quarter” (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for “non-QA operating quarters” (i.e., calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.1.2 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, “annual” means once every four “QA operating quarters” (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly
and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3.1 Out-of-Control Periods. A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 Grace Periods. For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 Conditional Data Validation For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (i.e., 168 unit or stack operating hours).

5.4 Data Validation.

5.4.1 Out-of-Control Periods. An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was
either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 Grace Periods. For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 Conditional Data Validation. For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in §75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (i.e., 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that
the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 General Requirements for HCl and HF CEMS.

8.1.1 Preventive Maintenance. Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 Recordkeeping and Reporting. Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 Maintenance Records. Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system’s ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 Specific Requirements for HCl and HF CEMS. The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with §60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in Appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by $9.43 \times 10^{-8}$ to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is $5.18 \times 10^{-8}$. The appropriate diluent cap value from section 6.2.1.2 of Appendix A to this subpart may be used to calculate the HCl or HF emission rate (lb/MMBtu) during startup or shutdown hours.

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of $K$ with $9.43 \times 10^{-8}$ lb/scf-ppm (for HCl) or $5.18 \times 10^{-8}$ (for HF) and defining $C$, as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in §63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.
9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term $E_{ho}$ in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 Monitoring Plan Records. For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (i.e., flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 Updates. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 Contents of the Monitoring Plan. For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under §75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 Electronic. Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (i.e., CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 Hard Copy. Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 Operating Parameter Records. For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in §63.10042).
10.1.3  

**HCl and/or HF Emissions Records.** For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1  The date and hour;

10.1.3.2  Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3  The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4  A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5  Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

10.1.4  

**Stack Gas Volumetric Flow Rate Records.**

10.1.4.1  Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (i.e., lb/MWh or lb/GWh).

10.1.4.2  Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

10.1.5  

**Records of Stack Gas Moisture Content.**

10.1.5.1  Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1  To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2  To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2  If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from §75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

10.1.6  

**Records of Diluent Gas (CO₂ or O₂) Concentration.**

10.1.6.1  To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO₂ or O₂ concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2  If hourly measurements of diluent gas concentration are needed, you must use a certified CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO₂ or O₂ concentration records, as specified in §75.57(g) of this chapter.

10.1.7  

**HCl and HF Emission Rate Records.** For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1  The date and hour;
10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.7.5 If applicable, a code to indicate that the default electrical load (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.7.6 If applicable, a code to indicate that the diluent cap (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.8 Certification and Quality Assurance Test Records. For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 HCl and HF CEMS.

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 Additional Monitoring Systems. For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and ongoing quality-assurance tests of these systems, as specified in §75.59(a) of this chapter.

11. Reporting Requirements

11.1 General Reporting Provisions. The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 Notifications. The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with §63.10030.
11.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in §63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 Certification, Recertification, and Quality-Assurance Test Reporting Requirements. Except for daily QA tests (i.e., calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in §75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:
11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems. For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 Quarterly Reports.

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;
11.5.3.3  The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4  The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5  If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4  Compliance Certification. Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

ARTICLE 24. CROSS-STATE AIR POLLUTION RULE (CSAPR) PROGRAMS

Rule 1. Clean Air Interstate Rule Nitrogen Oxides Annual Trading Program *(Repealed)*
(Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

Rule 2. Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program *(Repealed)*
(Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

Rule 3. Clean Air Interstate Rule (CAIR) NOx Ozone Season Trading Program

326 IAC 24-3-1 Applicability

Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 1. Any large affected unit as defined in section 2 of this rule, shall be a CAIR NOx ozone season unit, and any source that includes one (1) or more such units shall be a CAIR NOx ozone season source, and shall be subject to the requirements of this rule. *(Air Pollution Control Division; 326 IAC 24-3-1; filed Jan 26, 2007, 10:25 a.m.: 20070221-IR-326050117FRA; filed May 12, 2009, 11:16 a.m.: 20090610-IR-326080005FRA; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)*

326 IAC 24-3-2 Definitions

Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-11-2; IC 13-15; IC 13-17

Sec. 2. For purposes of this rule, the definition given for a term in this rule shall control in any conflict between 326 IAC 1-2 and this rule. In addition to the definitions provided in IC 13-11-2 and 326 IAC 1-2, the following definitions apply throughout this rule, unless expressly stated otherwise or unless the context clearly implies otherwise:

(1) "Account number" means the identification number given by the U.S. EPA to each CAIR NOx ozone season allowance tracking system account.
(2) "Acid rain emissions limitation" means a limitation on emissions of sulfur dioxide or nitrogen oxides under the acid rain program.
(3) "Acid rain program" means a multistate sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the U.S. EPA under Title IV of the Clean Air Act and 40 CFR Parts 72 through 40 CFR 78*.
(4) "Allocate" or "allocation" means, with regard to CAIR NOx ozone season allowances, the determination by a permitting authority or the U.S. EPA of the amount of such CAIR NOx ozone season allowances to be initially credited to a CAIR NOx ozone season unit, a new unit set-aside, an energy efficiency or renewable energy set-aside, or other entity.
(5) "Allowance transfer deadline" means, for a control period, midnight of November 30 (if it is a business day), or midnight of the first business day thereafter (if November 30 is not a business day), immediately following the control period and is the deadline by which a CAIR NOx ozone season allowance must be submitted for recordation in a CAIR NOx source’s compliance account in order to be used to meet the source’s CAIR NOx ozone season emissions limitation for such control period in accordance with sections 9(i) and 9(j) of this rule.
(6) "Alternate CAIR designated representative" means, for a CAIR NOx ozone season source and each CAIR NOx ozone season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with sections 6 and 12 of this rule, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NOx ozone season trading program. If the CAIR NOx ozone season source is also a CAIR NOx source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NOx annual trading program. If the CAIR NOx ozone season source is also a CAIR NOx source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NOx annual trading program. If the CAIR NOx ozone season source is also subject to the acid rain program, then this natural person shall be the same person as the alternate designated representative under the acid rain program. If the CAIR NOx ozone season source is also subject to the mercury budget trading program, then this natural person shall be the same person as the alternate mercury designated representative under the mercury budget trading program.
(7) "Automated data acquisition and handling system" or "DAHS" means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under section 11 of this rule, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by section 11 of this rule.

(8) "Biomass" means any of the following:

(A) Organic material grown for the purpose of being converted to energy.

(B) Organic byproduct of agriculture that can be converted into energy.

(C) Material that:

(i) can be converted into energy and is nonmerchantable for other purposes;

(ii) is segregated from other nonmerchantable material; and

(iii) is:

(AA) a forest-related organic residue, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(BB) a wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way thinnings.

(9) "Boiler" means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

(10) "Bottoming-cycle cogeneration unit" means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

(11) "CAIR authorized account representative" means, with regard to a general account, a responsible natural person who is authorized, in accordance with sections 6, 9, and 12 of this rule, to transfer and otherwise dispose of CAIR NOx ozone season allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

(12) "CAIR designated representative" means, for a CAIR NOx ozone season source and each CAIR NOx ozone season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with sections 6 and 12 of this rule, to represent and legally bind each owner and operator in matters pertaining to the CAIR NOx ozone season trading program. If the CAIR NOx ozone season source is also a CAIR NOx source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NOx annual trading program. If the CAIR NOx ozone season source is also a CAIR SO2 source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NOx trading program. If the CAIR NOx ozone season source is also subject to the acid rain program, then this natural person shall be the same person as the designated representative under the acid rain program.

(13) "CAIR NOx annual trading program" means a multistate nitrogen oxides air pollution control and emission reduction program approved and administered by the U.S. EPA in accordance with 326 IAC 24-1; 40 CFR 96, Subparts AA through II* and 40 CFR 51.123(o)(1) or 40 CFR 51.123(o)(2)*; or established by the U.S. EPA in accordance with 40 CFR 97, Subparts AA through II* and 40 CFR 51.123(p)* and 40 CFR 52.35*, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

(14) "CAIR NOx ozone season allowance" means a limited authorization issued by a permitting authority or the U.S. EPA under provisions of a state implementation plan that are approved under 40 CFR 51.123(aa)(1) or 40 CFR 51.123(aa)(2), and 40 CFR 51.123(bb)(1), 40 CFR 51.123(bb)(2), 40 CFR 51.123(dd), or 40 CFR 51.123(ee)*, or under 40 CFR 97*, to emit one (1) ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NOx ozone season trading program or a limited authorization issued by a permitting authority for a control period during 2003 through 2009 under the NOx budget trading program in accordance with 40 CFR 51.121(p)* or 326 IAC 10-4 to emit one (1) ton of nitrogen oxides during a control period, provided that the provision in 40 CFR 51.121(b)(2)(ii)(E)* shall not be used in applying this definition and the limited authorization shall not have been used to meet the allowance-holding requirement under the NOx budget trading program. An authorization to emit nitrogen oxides that is not issued under provisions of a state implementation plan approved under 40 CFR 51.121(p)* or 40 CFR 51.123(aa)(1) or 40 CFR 51.123(aa)(2), and 40 CFR 51.123(bb)(1), 40 CFR 51.123(bb)(2), 40 CFR 51.123(dd), or 40 CFR 51.123(ee)*, or under 40 CFR 97* shall not be a CAIR NOx ozone season allowance.

(15) "CAIR NOx ozone season allowance deduction" or "deduct CAIR NOx ozone season allowances" means the permanent withdrawal of CAIR NOx ozone season allowances by the U.S. EPA from a compliance account, for example, in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR
NOx ozone season units at a CAIR NOx ozone season source for a control period, determined in accordance with section 11 of this rule, or to account for excess emissions.

(16) "CAIR NOx ozone season allowances held" or "hold CAIR NOx ozone season allowances" means the CAIR NOx ozone season allowances recorded by the U.S. EPA, or submitted to the U.S. EPA for recordation, in accordance with sections 9, 10, and 12 of this rule, in a CAIR NOx ozone season allowance tracking system account.

(17) "CAIR NOx ozone season allowance tracking system" means the system by which the U.S. EPA records allocations, deductions, and transfers of CAIR NOx ozone season allowances under the CAIR NOx ozone season trading program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

(18) "CAIR NOx ozone season allowance tracking system account" means an account in the CAIR NOx ozone season allowance tracking system established by the U.S. EPA for purposes of recording the allocation, holding, transferring, or deducting of CAIR NOx ozone season allowances.

(19) "CAIR NOx ozone season emissions limitation" means, for a CAIR NOx ozone season source, the tonnage equivalent, in NOx emissions in a control period, of the CAIR NOx ozone season allowances available for deduction for the source under section 9(i) and 9(j)(1) of this rule for the control period.

(20) "CAIR NOx ozone season source" means a source that includes one (1) or more CAIR NOx ozone season units.

(21) "CAIR NOx ozone season trading program" means a multistate nitrogen oxides air pollution control and emission reduction program approved and administered by the U.S. EPA in accordance with this rule; 40 CFR 96, Subparts AAAA through III* and 40 CFR 51.123(aa)(1) or 40 CFR 51.123(aa)(2), and 40 CFR 51.123(bb)(1), 40 CFR 51.123(bb)(2), or 40 CFR 51.123(dd)*; or established by the U.S. EPA in accordance with 40 CFR 97, Subparts AAA through III* and 40 CFR 51.123(ee)* and 40 CFR 52.35*, as a means of mitigating interstate transport of ozone and nitrogen oxides.

(22) "CAIR NOx ozone season unit" means a unit that is subject to the CAIR NOx ozone season trading program under section 1 of this rule and, for the purposes of sections 3 and 8 of this rule, a CAIR NOx ozone season opt-in unit under section 12 of this rule.

(23) "CAIR NOx source" means a source that is subject to the CAIR NOx annual trading program.

(24) "CAIR permit" means the legally binding and federally enforceable written document, or portion of such document, issued by the department under section 7 of this rule, including any permit revisions, specifying the CAIR NOx ozone season trading program requirements applicable to a CAIR NOx ozone season source, to each CAIR NOx ozone season unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

(25) "CAIR SO2 source" means a source that is subject to the CAIR SO2 trading program.

(26) "CAIR SO2 trading program" means a multistate sulfur dioxide air pollution control and emission reduction program approved and administered by the U.S. EPA in accordance with 326 IAC 24-2; 40 CFR 96, Subparts AAA through III* and 40 CFR 51.124(o)(1) or 40 CFR 51.124(o)(2)*; or established in accordance with 40 CFR 97, Subparts AAA through III and 40 CFR 51.124(r)* and 40 CFR 52.36*, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

(27) "Coal" means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

(28) "Coal-derived fuel" means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal.

(29) "Coal-fired" means:

(A) except for purposes of section 8 of this rule, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(B) for purposes of section 8 of this rule, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

(30) "Cogeneration unit" means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(A) having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy;

(B) producing electricity during the twelve (12) month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity:

(i) for a topping-cycle cogeneration unit:

(AA) useful thermal energy not less than five percent (5%) of total energy output; and

(BB) useful power that, when added to one-half (½) of useful thermal energy produced, is not less than forty-two and one-half percent (42.5%) of total energy output.
input, if useful thermal energy produced is fifteen percent (15%) or more of total energy output, or not less than forty-five percent (45%) of total energy input, if useful thermal energy produced is less than fifteen percent (15%) of total energy output; and

(ii) for a bottoming-cycle cogeneration unit, useful power not less than forty-five percent (45%) of total energy input; and

(C) provided that the total energy input under clause (B)(i)(BB) and (B)(ii) shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

(31) "Combustion turbine" means:

(A) an enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(B) if the enclosed device under clause (A) is combined cycle, any associated duct burner, heat recovery steam generator and steam turbine.

(32) "Commence commercial operation" means, with regard to a unit serving a generator, the following:

(A) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in sections 3 and 12(f)(10) of this rule, subject to the following:

(i) For a unit that is a CAIR NOx ozone season unit under section 1 of this rule on the later of November 15, 1990, or the date the unit commences commercial operation as defined in this clause and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source) such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a CAIR NOx ozone season unit under section 1 of this rule on the later of November 15, 1990, or the date the unit commences commercial operation as defined in this clause and that is subsequently replaced by a unit at the same source (for example, repowered), such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in this clause or clause (B) as appropriate.

(B) Notwithstanding clause (A) and except as provided in section 3 of this rule, for a unit that is not a CAIR NOx ozone season unit under section 1 of this rule on the later of November 15, 1990, or the date the unit commences commercial operation as defined in clause (A), the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NOx ozone season unit under section 1 of this rule, subject to the following:

(i) For a unit with a date for commencement of commercial operation as defined in this clause and that subsequently undergoes a physical change, other than replacement of the unit by a unit at the same source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in this clause and that is subsequently replaced by a unit at the same source (for example, repowered), such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in this clause or clause (A), as appropriate.

(C) Notwithstanding clauses (A) and (B), for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

(33) "Commence operation" means the following:

(A) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in section 12(f)(10) of this rule.

(B) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in clause (A), such date shall remain the unit's date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(C) For a unit that is replaced by a unit at the same source (for example, repowered) after the date the unit commences operation as defined in clause (A), such date shall remain the replaced unit's date of commencement, and the replacement unit shall be treated as a separate unit with a separate
date for commencement of operation as defined in this clause or clause (A) or (B), as appropriate, except as provided in section 12(f)(10) of this rule.

(D) Notwithstanding clauses (A) through (C), and solely for purposes of section 11 of this rule, for a unit that is not a large affected unit under subdivision (51)(A) or (51)(B) on the later of November 15, 1990, or the date the unit commences operation as defined in clause (A) and that subsequently becomes a large affected unit under subdivision (51)(A) or (51)(B), the unit's date for commencement of operation shall be the date on which the unit becomes a large affected unit under subdivision (51)(A) or (51)(B).

(E) For a unit with a date of commencement of operation as defined in clause (D) and that subsequently undergoes a physical change, other than replacement of the unit by a unit at the same source, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(F) For a unit with a date for commencement of operation as defined in clause (D) and that is subsequently replaced by a unit at the same source, for example, repowered, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in this clause and clauses (A) through (E), as appropriate.

(34) "Common stack" means a single flue through which emissions from two (2) or more units are exhausted.

(35) "Compliance account" means a CAIR NOx ozone season allowance tracking system account, established by the U.S. EPA for a CAIR NOx ozone season source under section 9 or 12 of this rule, in which any CAIR NOx ozone season allowance allocations for the CAIR NOx ozone season units at the source are initially recorded and in which are held any CAIR NOx ozone season allowances available for use for a control period in order to meet the source's CAIR NOx ozone season emissions limitation in accordance with section 9(i) and 9(j) of this rule.

(36) "Continuous emission monitoring system" or "CEMS" means the equipment required under section 11 of this rule to sample, analyze, measure, and provide, by means of readings recorded at least once every fifteen (15) minutes, using an automated data acquisition and handling system (DAHS), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration, as applicable, in a manner consistent with 40 CFR 75*. The following systems are the principal types of continuous emission monitoring systems required under section 11 of this rule:

(A) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh).

(B) A nitrogen oxides concentration monitoring system, consisting of a NOx ozone season pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NOx ozone season emissions, in parts per million (ppm).

(C) A nitrogen oxides emission rate (or NOx-diluent) monitoring system, consisting of a NOx ozone season pollutant concentration monitor, a diluent gas (CO2 or O2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NOx ozone season concentration, in parts per million (ppm), diluent gas concentration, in percent CO2 or O2; and NOx ozone season emission rate, in pounds per million British thermal units (lb/MMBtu).

(D) A moisture monitoring system, as defined in 40 CFR 75.11(b)(2)* and providing a permanent, continuous record of the stack gas moisture content, in percent H2O.

(E) A carbon dioxide monitoring system, consisting of a CO2 pollutant concentration monitor, or an oxygen monitor plus suitable mathematical equations from which the CO2 concentration is derived, and an automated data acquisition and handling system and providing a permanent, continuous record of CO2 emissions, in percent CO2.

(F) An oxygen monitoring system, consisting of an O2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O2, in percent O2.

(37) "Control period" means the period beginning May 1 of a calendar year, except as provided in section 4(c)(2) of this rule, and ending on September 30 of the same year, inclusive.

(38) "Electricity for sale under a firm contract to the electric grid" means electricity for sale where the capacity involved is intended to be available at all times during the period covered by the guaranteed commitment to deliver, even under adverse conditions.

(39) "Emissions" means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the U.S. EPA by the CAIR designated representative and as determined by the U.S. EPA in accordance with section 11 of this rule.

(40) "Energy efficiency or renewable energy projects" means any of the following implemented in Indiana:

(A) End-use energy efficiency projects, including demand-side management programs.
(B) Highly efficient electricity or steam generation for the predominant use of a single end user, such as combined cycle, combined heat and power, microturbines, and fuel cell systems. In order to be considered as highly efficient electricity generation under this clause, combined cycle, combined heat and power, microturbines, and fuel cell generating systems must meet or exceed the following thresholds:

(i) For combined heat and power projects generating both electricity and thermal energy for space, water, or industrial process heat, rated energy efficiency of sixty percent (60%).

(ii) For microturbine projects rated at or below five hundred (500) kilowatts generating capacity, rated energy efficiency of forty percent (40%).

(iii) For combined cycle projects rated at greater than five hundred (500) kilowatts, rated energy efficiency of fifty percent (50%).

(iv) For fuel cell systems, rated energy efficiency of forty percent (40%), whether or not the fuel cell system is part of a combined heat and power energy system.

(C) Zero-emission renewable energy projects, including wind, photovoltaic, solar, and hydropower projects. Eligible hydropower projects are restricted to systems employing a head of ten (10) feet or less or systems employing a head greater than ten (10) feet that make use of a dam that existed before September 16, 2001.

(D) Energy efficiency projects generating electricity through the capture of methane gas from municipal solid waste landfills, water treatment plants, sewage treatment plants, or anaerobic digestion systems operating on animal or plant wastes.

(E) The installation of highly efficient electricity generation equipment for the sale of power where such equipment replaces or displaces retired electrical generating units. In order to be considered as highly efficient under this clause, generation equipment must meet or exceed the following energy efficiency thresholds:

(i) For coal-fired electrical generation units, rated energy efficiency of forty-two percent (42%).

(ii) For natural gas-fired electrical generating units, rated energy efficiency of fifty percent (50%).

(F) Improvements to existing fossil fuel-fired electrical generation units that increase the efficiency of the unit and decrease the heat rate used to generate electricity, including gas reburning projects that reduce NOx emissions.

(G) The installation of integrated gasification combined cycle equipment producing electricity for sale.

(H) Renewable energy projects that displace some portion of the combustion of coal, natural gas, or oil through the use of solar energy or methane from landfills, water treatment plants, sewage treatment plants, or anaerobic digestion systems on animal or plant wastes and reduce NOx emissions.

Energy efficiency or renewable energy projects do not include nuclear power projects. This definition is solely for the purposes of implementing this rule and does not apply in other contexts.

(41) "Excess emissions" means any ton of nitrogen oxides emitted by the CAIR NOx ozone season units at a CAIR NOx ozone season source during a control period that exceeds the CAIR NOx ozone season emissions limitation for the source.

(42) "FESOP" means a federally enforceable state operating permit issued under 326 IAC 2-8.

(43) "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

(44) "Fossil-fuel-fired" means, with regard to a unit, the following:

(A) Except as provided in clause (B), combusting any amount of fossil fuel in any calendar year.

(B) Solely for the purposes of applying the term "large affected unit", the combustion of fossil fuel, alone or in combination with any other fuel, under any of the following scenarios:

(i) Fossil fuel actually combusted composites more than fifty percent (50%) of the annual heat input on a British thermal unit (Btu) basis during any year starting in 1995. If a unit had no heat input starting in 1995, during the last year of operation of the unit prior to 1995.

(ii) Fossil fuel is projected to comprise more than fifty percent (50%) of the annual heat input on a Btu basis during any year, provided that the unit shall be fossil-fuel-fired as of the date, during the year, that the unit beginscombusting fossil fuel.

(45) "Fuel oil" means any petroleum-based fuel, including diesel fuel or petroleum derivatives such as oil tar, any recycled or blended petroleum products or petroleum byproducts used as a fuel whether in a liquid, solid, or gaseous state.

(46) "General account" means a CAIR NOx ozone season allowance tracking system account, established under section 9 of this rule, that is not a compliance account.
(47) "Generator" means a device that produces electricity.
(48) "Gross electrical output" means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process. This process may include, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls.
(49) "Heat input" means, with regard to a specified period of time, the product, in million British thermal units per unit of time (MMBtu/time) of the gross calorific value of the fuel, in British thermal units per pound (Btu/lb), divided by one million (1,000,000) British thermal units per million British thermal units (Btu/MMBtu) and multiplied by the fuel feed rate into a combustion device, in pounds of fuel per unit of time (lb of fuel/time), as measured, recorded, and reported to the U.S. EPA by the CAIR designated representative and determined by the U.S. EPA in accordance with section 11 of this rule and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.
(50) "Heat input rate" means the amount of heat input, in million British thermal units (MMBtu), divided by unit operating time, in hours, or, with regard to a specific fuel, the amount of heat input attributed to the fuel, in million British thermal units (MMBtu), divided by the unit operating time, in hours, during which the unit combusts the fuel.
(51) "Large affected unit" means the following:
   (A) For units other than cogeneration units commencing operation, the following:
       (i) Before January 1, 1997, a unit that has a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid.
       (ii) On or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.
       (iii) On or after January 1, 1999, a unit with a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour that:
           (AA) at no time serves a generator producing electricity for sale; or
           (BB) at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of twenty-five (25) megawatt electrical or less and has the potential to use no more than fifty percent (50%) of the potential electrical output capacity of the unit.
   (B) For cogeneration units commencing operation, the following:
       (i) Before January 1, 1997, a unit with a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour and qualifying as an unaffected unit under the acid rain program for 1995 and 1996.
       (ii) In 1997 or 1998, a unit with a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour and qualifying as an unaffected unit under the acid rain program for 1997 and 1998.
       (iii) On or after January 1, 1999, a unit with a maximum design heat input greater than two hundred fifty million (250,000,000) Btus per hour and qualifying as an unaffected unit under the acid rain program for each year.
   (C) For units other than cogeneration units that are not already subject to this rule under section 1(a)(1) or 1(a)(3) of this rule commencing operation:
       (i) before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity greater than twenty-five (25) megawatts and produced electricity for sale under a firm contract to the electric grid;
       (ii) on or after January 1, 1997, and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity greater than twenty-five (25) megawatts and produced electricity for sale under a firm contract to the electric grid; or
       (iii) on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity greater than twenty-five (25) megawatts and produced electricity for sale under a firm contract to the electric grid.
   (D) For cogeneration units that are not already subject to this rule under section 1(a)(1) or 1(a)(3) of this rule commencing operation:
       (i) before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity greater than twenty-five (25) megawatts and failing to qualify as an unaffected unit for 1995 or 1996 under the acid rain program;
(ii) in 1997 or 1998, a unit serving a generator during 1997 or 1998 with a nameplate capacity greater than twenty-five (25) megawatts and failing to qualify as an unaffected unit for 1997 or 1998 under the acid rain program; or

(iii) on or after January 1, 1999, a unit serving at any time a generator with a nameplate capacity greater than twenty-five (25) megawatts and failing to qualify as an unaffected unit under the acid rain program for any year.

The term does not include a unit subject to 326 IAC 10-3.

(52) "Life-of-the-unit, firm power contractual arrangement" means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(A) for the life of the unit;
(B) for a cumulative term of no less than thirty (30) years, including contracts that permit an election for early termination; or
(C) for a period no less than twenty-five (25) years or seventy percent (70%) of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

(53) "Maximum design heat input" means the maximum amount of fuel per hour, in British thermal units per hour (Btu/hr), that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

(54) "Mercury budget trading program" means a multistate mercury air pollution control and emission reduction program approved and administered by the U.S. EPA in accordance with 40 CFR 60, Subpart HHHH* and 40 CFR 60.24(h)(6)*, or established by the U.S. EPA under the Clean Air Act, Section 111, as a means of reducing national mercury emissions.

(55) "Monitoring system" means any monitoring system that meets the requirements of section 11 of this rule, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under 40 CFR 75*.

(56) "Most stringent state or federal NOx emissions limitation" means, with regard to a unit, the lowest NOx emissions limitation, in terms of pounds per million British thermal units (lb/MMBtu), that is applicable to the unit under state or federal law, regardless of the averaging period to which the emissions limitation applies.

(57) "Nameplate capacity" means, starting from the initial installation of a generator, the maximum electrical generating output, in megawatt electrical (MWe), that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output, in megawatt electrical (MWe), that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) such increased maximum amount as of such completion as specified by the person conducting the physical change.

(58) "Oil-fired" means, for the purposes of section 8 of this rule, combusting fuel oil for more than fifteen percent (15%) of the annual heat input in a specified year and not qualifying as coal-fired.

(59) "Operator" means any person who operates, controls, or supervises a CAIR NOx ozone season unit or a CAIR NOx ozone season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

(60) "Owner" means any of the following persons:

(A) With regard to a CAIR NOx ozone season source or a CAIR NOx ozone season unit at a source, respectively, any of the following:

(i) Holder of any portion of the legal or equitable title in a CAIR NOx ozone season unit at the source or the CAIR NOx ozone season unit.
(ii) Holder of a leasehold interest in a CAIR NOx ozone season unit at the source or the CAIR NOx ozone season unit.
(iii) Purchaser of power from a CAIR NOx ozone season unit at the source or the CAIR NOx ozone season unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, on the revenues or income from such CAIR NOx ozone season unit.

(B) With regard to any general account, any person who has an ownership interest with respect to the CAIR NOx ozone season allowances held in the general account and who is subject to the binding
agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR NOx ozone season allowances.

(61) "Permitting authority" means the state air pollution control agency, local agency, other state agency, or other agency authorized by the U.S. EPA to issue or revise permits to meet the requirements of the CAIR NOx annual trading program or, if no such agency has been so authorized, the U.S. EPA.

(62) "Potential electrical output capacity" means thirty-three percent (33%) of a unit's maximum design heat input, divided by three thousand four hundred thirteen (3,413) Btu/kilowatt hour, divided by one thousand (1,000) kilowatt hour/megawatt hour, and multiplied by eight thousand seven hundred sixty (8,760) hours/year.

(63) "Rated energy efficiency" means the percentage of gross energy input that is recovered as usable net energy output in the form of electricity or thermal energy, or both, that is used for heating, cooling, industrial processes, or other beneficial uses as follows:

(A) For electric generators, rated energy efficiency is calculated as one (1) net kilowatt hour (three thousand four hundred twelve (3,412) British thermal units) of electricity divided by the unit's design heat rate using the higher heating value of the fuel.

(B) For combined heat and power projects, rated energy efficiency is calculated using the following formula:

\[
\text{Eff\%} = \frac{\text{NEO} + \text{UTO}}{\text{GEI}}
\]

Where:

- \(\text{Eff\%}\) = Rated energy efficiency.
- \(\text{NEO}\) = Net electrical output of the system converted to British thermal units per unit of time.
- \(\text{UTO}\) = Utilized thermal output or the energy value in British thermal units of thermal energy from the system that is used for heating, cooling, industrial processes, or other beneficial uses, per unit of time.
- \(\text{GEI}\) = Gross energy input, based upon the higher heating value of fuel, per unit of time.

(64) "Receive" or "receipt of" means, when referring to the department or U.S. EPA, to come into possession of a document, information, or correspondence, whether sent in hard copy or by authorized electronic transmission, as indicated in an official log, or by a notation made on the document, information, or correspondence, by the department or U.S. EPA in the regular course of business.

(65) "Recordation", "record", or "recorded" means, with regard to CAIR NOx ozone season allowances, the movement of CAIR NOx ozone season allowances by the U.S. EPA into or between CAIR NOx ozone season allowance tracking system accounts, for purposes of allocation, transfer, or deduction.

(66) "Reference method" means any direct test method of sampling and analyzing for an air pollutant as specified in 40 CFR 75.22*.

(67) "Replacement", "replace", or "replaced" means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

(68) "Repowered" means, with regard to a unit, replacement of a coal-fired boiler with one (1) of the following coal-fired technologies at the same source as the coal-fired boiler:

(A) Atmospheric or pressurized fluidized bed combustion.

(B) Integrated gasification combined cycle.

(C) Magnetohydrodynamics.

(D) Direct and indirect coal-fired turbines.

(E) Integrated gasification fuel cells.

(F) As determined by the U.S. EPA in consultation with the Secretary of Energy, a derivative of one (1) or more of the technologies under clauses (A) through (E) and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

(69) "Sequential use of energy" means:

(A) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(B) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

(70) "Serial number" means, for a CAIR NOx ozone season allowance, the unique identification number assigned to each CAIR NOx ozone season allowance by the U.S. EPA.

(71) "Solid waste incineration unit" means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a solid waste incineration units as defined in the Clean Air Act, Section 129(g)(1).
(72) "Source" means all buildings, structures, or installations located in one (1) or more contiguous or adjacent properties under common control of the same person or persons. For purposes of Section 502(c) of the Clean Air Act, a source, including a source with multiple units, shall be considered a single facility.

(73) "Submit" or "serve" means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable rule:
   (A) in person;
   (B) by United States Postal Service; or
   (C) by other means of dispatch or transmission and delivery.

Compliance with any submission or service deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt by the department or U.S. EPA.

(74) "Title V operating permit" or "Part 70 operating permit" means a permit issued under 326 IAC 2-7.

(75) "Title V operating permit regulations" or "Part 70 operating permit regulations" means the rules under 326 IAC 2-7.

(76) "Ton" means two thousand (2,000) pounds. For the purpose of determining compliance with the CAIR NOx ozone season emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions, or the mass equivalent of the recorded hourly emission rates, in accordance with section 11 of this rule, but with any remaining fraction of a ton equal to or greater than fifty-hundredths (0.50) tons deemed to equal one (1) ton and any remaining fraction of a ton less than fifty-hundredths (0.50) tons deemed to equal zero (0) tons.

(77) "Topping-cycle cogeneration unit" means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

(78) "Total energy input" means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
LHV = HHV - 10.55(W + 9H)
\]

Where:

- \( LHV \) = Lower heating value of fuel in Btu/hr.
- \( HHV \) = Higher heating value of fuel in Btu/hr.
- \( W \) = Weight % of moisture in fuel.
- \( H \) = Weight % of hydrogen in fuel.

(79) "Total energy output" means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

(80) "Unit" means:
   (A) except as provided in clause (B), a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device; and
   (B) solely for the purposes of applying the term "large affected unit", a fossil-fuel-fired:
      (i) stationary boiler;
      (ii) combustion turbine; or
      (iii) combined cycle system.

(81) "Unit operating day" means a calendar day in which a unit combusts any fuel.

(82) "Unit operating hour" or "hour of unit operation" means an hour in which a unit combusts any fuel.

(83) "Useful power" means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process, which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls.

(84) "Useful thermal energy" means, with regard to a cogeneration unit, thermal energy that is:
   (A) made available to an industrial or commercial process, not a power production process, excluding any heat contained in condensate return or makeup water;
   (B) used in a heating application (for example, space heating or domestic hot water heating); or
   (C) used in a space cooling application (that is, thermal energy used by an absorption chiller).

(85) "Utility power distribution system" means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

*These documents are incorporated by reference. Copies may be obtained from the Government Printing Office, 732 North Capitol Street NW, Washington, D.C. 20401 or are available for review and copying at the Indiana Department of Environmental Management, Office of Air Quality, Indiana Government Center-North, Tenth Floor, 100 North Senate Avenue, Indianapolis, Indiana 46204. (Air Pollution Control Division; 326 IAC 24-3-2; filed Jan 26, 2007, 10:25 a.m.: 20070221-IR-326050117FRA; errata filed Jan 29, 2007, 2:43 p.m.: 20070221-IR-326050117ACA; filed May 12, 2009, 11:16 a.m.: 20090610-IR-326080005FRA)*
326 IAC 24-3-3 Retired unit exemption (Repealed)

Sec. 3. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-4 Standard requirements
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 4. The owners and operators, and the CAIR designated representative, of each CAIR NOx ozone season source and CAIR NOx ozone season unit at the source shall comply with the monitoring, reporting, and record keeping requirements of section 11 of this rule. (Air Pollution Control Division; 326 IAC 24-3-4; filed Jan 26, 2007, 10:25 a.m.: 20070221-IR-326050117FRA; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-5 Computation of time and appeal procedures (Repealed)

Sec. 5. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-6 CAIR designated representative for CAIR NOx ozone season sources (Repealed)

Sec. 6. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-7 Permit requirements (Repealed)

Sec. 7. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-8 CAIR NOx ozone season allowance allocations (Repealed)

Sec. 8. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-9 CAIR NOx ozone season allowance tracking system (Repealed)

Sec. 9. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-10 CAIR NOx ozone season allowance transfers (Repealed)

Sec. 10. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-3-11 Monitoring and reporting requirements
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 11. (a) The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NOx ozone season unit, shall comply with the monitoring, record keeping, and reporting requirements as provided in this rule and in 40 CFR 75, Subpart H*. For purposes of complying with such requirements, the definitions in section 2 of this rule and 40 CFR 72.2* shall apply, and the terms affected unit, designated representative, and continuous emission monitoring system (CEMS) in 40 CFR 75* shall be replaced by the terms CAIR NOx ozone season unit, CAIR designated representative, and continuous emission monitoring system (CEMS) respectively, as defined in section 2 of this rule. The owner or operator of a unit that is not a CAIR NOx ozone season unit but that is monitored under 40 CFR 75.72(b)(2)(ii)* shall comply with the same monitoring, record keeping, and reporting requirements as a CAIR NOx ozone season unit.

(b) The owner or operator of each CAIR NOx ozone season unit shall do the following:
(1) Install all monitoring systems required under this section for monitoring NOx ozone season mass emissions and individual unit heat input. This includes all systems required to monitor NOx ozone season emission rate, NOx ozone season concentration, stack gas moisture content, stack gas flow rate, CO2 or O2 concentration, and fuel flow rate, as applicable, in accordance with 40 CFR 75.71* and 40 CFR 75.72*.

(2) Successfully complete all certification tests required under subsections (f) through (j) and meet all other requirements of this section and 40 CFR 75* applicable to the monitoring systems under subdivision (1).

(3) Record, report, and quality-assure the data from the monitoring systems under subdivision (1).

(c) Except as provided in subsection (p), the owner or operator shall meet the monitoring system certification and other requirements of subsection (b)(1) and (b)(2) on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under subsection (b)(1) on and after the following dates:

   (1) For the owner or operator of a CAIR NOx ozone season unit that commences commercial operation before July 1, 2007, by May 1, 2008.

   (2) For the owner or operator of a CAIR NOx ozone season unit that commences commercial operation on or after July 1, 2007, and that reports on an annual basis under subsection (n)(3), by the later of the following dates:

      (A) May 1, 2008.

      (B) The earlier of:

         (i) one hundred eighty (180) calendar days after the date on which the unit commences commercial operation; or

         (ii) ninety (90) unit operating days after the date on which the unit commences commercial operation.

   (3) For the owner or operator of a CAIR NOx ozone season unit that commences commercial operation on or after July 1, 2007, and that reports on a control period basis under subsection (n)(3)(B)(ii), by the later of the following dates:

      (A) If the compliance date under clause (B) is not during a control period, May 1 immediately following the compliance date under clause (B).

      (B) The earlier of:

         (i) one hundred eighty (180) calendar days after the date on which the unit commences commercial operation; or

         (ii) ninety (90) unit operating days after the date on which the unit commences commercial operation.

   (4) For the owner or operator of a CAIR NOx ozone season unit for which construction of a new stack or flue or installation of add-on NOx emission controls is completed after the applicable deadline under subdivisions (1), (2), (6), or (7) and that reports on an annual basis under subsection (n)(3), compliance by the earlier of:

      (A) one hundred eighty (180) calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOx emissions controls; or

      (B) ninety (90) unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOx emissions controls.

   (5) For the owner or operator of a CAIR NOx ozone season unit for which construction of a new stack or flue or installation of add-on NOx emission controls is completed after the applicable deadline under subdivision (1), (3), (6), or (7) and that reports on control period basis under subsection (n)(3)(B)(ii), by the later of the following dates:

      (A) If the compliance date under clause (B) is not during a control period, May 1 immediately following the compliance date under clause (B).

      (B) The earlier of:

         (i) one hundred eighty (180) calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOx emissions controls; or

         (ii) ninety (90) unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOx emissions controls.

   (6) Notwithstanding the dates in subdivisions (1) through (3), for the owner or operator of a unit for which a CAIR NOx ozone season opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under section 12 of this rule, by the date specified in section 12(f)(2) through 12(f)(4) of this rule.

   (7) Notwithstanding the dates in subdivisions (1), (2), and (3), for the owner or operator of a CAIR NOx ozone season opt-in unit, by the date on which the CAIR NOx ozone season opt-in unit under section 12 of this rule enters the CAIR NOx ozone season trading program as provided in section 12(f)(9) of this rule.

(d) The owner or operator of a CAIR NOx ozone season unit that does not meet the applicable compliance date set forth in subsection (c) for any monitoring system under subsection (b)(1) shall, for each such monitoring...
(e) The following shall apply to any monitoring system, alternative monitoring system, alternative reference method, or any other alternative for a CEMS required under this rule:

(1) No owner or operator of a CAIR NOx ozone season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this section without having obtained prior written approval in accordance with subsection (o).

(2) No owner or operator of a CAIR NOx ozone season unit shall operate the unit so as to discharge, or allow to be discharged, NOx ozone season emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this section and 40 CFR 75*.

(3) No owner or operator of a CAIR NOx ozone season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx ozone season mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this section and 40 CFR 75*.

(4) No owner or operator of a CAIR NOx ozone season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this section, except under any one (1) of the following circumstances:

(A) During the period that the unit is covered by an exemption under section 3 of this rule.

(B) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this section and 40 CFR 75*, by the department for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system.

(C) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with subsection (h)(3)(A).

(f) The owner or operator of a CAIR NOx ozone season unit shall be exempt from the initial certification requirements of this subsection and subsections (g) through (j) for a monitoring system under subsection (b)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with 40 CFR 75*.

(2) The applicable quality-assurance and quality-control requirements of 40 CFR 75.21*, 40 CFR 75, Appendix B*, 40 CFR 75, Appendix D*, and 40 CFR 75, Appendix E* are fully met for the certified monitoring system described in subdivision (1).

The recertification provisions of this subsection and subsections (g) through (j) shall apply to a monitoring system under subsection (b)(1) exempt from initial certification requirements under this subsection.

(g) If the U.S. EPA has previously approved a petition under 40 CFR 75.17(a)* or 40 CFR 75.17(b)* for apportioning the NOx emission rate measured in a common stack or a petition under 40 CFR 75.66* for an alternative to a requirement in 40 CFR 75.12* or 40 CFR 75.17*, the CAIR designated representative shall resubmit the petition to the U.S. EPA under subsection (o)(1) to determine whether the approval applies under the CAIR NOx ozone season trading program.

(h) Except as provided in subsection (f), the owner or operator of a CAIR NOx ozone season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (that is, a continuous emission monitoring system and an excepted monitoring system under 40 CFR 75, Appendix D* and 40 CFR 75, Appendix E*) under subsection (b)(1). The owner or operator of a unit that qualifies to use the low mass emissions accepted monitoring methodology under 40 CFR 75.19* or that qualifies to use an alternative monitoring system under 40 CFR 75, Subpart E* shall comply with the procedures in subsection (i) or (j) respectively:

(1) The owner or operator shall ensure that each continuous monitoring system under subsection (b)(1), including the automated data acquisition and handling system, successfully completes all of the initial certification testing required under 40 CFR 75.20* by the applicable deadline in subsection (c). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this section in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20* is required.

(2) Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under subsection (b)(1) that may significantly affect the ability of the system to accurately measure or record NOx mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21* or 40 CFR 75, Appendix B*, the owner or operator shall recertify the monitoring system in accordance with 40 CFR 75.20(b)*. Furthermore, whenever the owner or operator...
makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with 40 CFR 75.20(b)*. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NOx monitoring system under 40 CFR 75, Appendix E*, under subsection (b)(1) are subject to the recertification requirements in 40 CFR 75.20(g)(6)*.

(3) Clauses (A) through (D) apply to both initial certification and recertification of a continuous monitoring system under subsection (b)(1). For recertifications, replace the words certification and initial certification with the word recertification, replace the word certified with the word recertified, and follow the procedures in 40 CFR 75.20(b)(5)* and 40 CFR 75.20(g)(7)* in lieu of the procedures in clause (E). Requirements for the certification approval process for initial certification and recertification, and loss of certification are as follows:

(A) The CAIR designated representative shall submit to the department, the appropriate EPA Regional Office, and the U.S. EPA written notice of the dates of certification testing, in accordance with subsection (m).

(B) The CAIR designated representative shall submit to the department a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63*.

(C) The provisional certification date for a monitoring system shall be determined in accordance with 40 CFR 75.20(a)(3)*. A provisionally certified monitoring system may be used under the CAIR NOx ozone season trading program for a period not to exceed one hundred twenty (120) days after receipt by the department of the complete certification application for the monitoring system under clause (B). Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of 40 CFR 75*, shall be considered valid quality-assured data, retroactive to the date and time of provisional certification, provided that the department does not invalidate the provisional certification by issuing a notice of disapproval within one hundred twenty (120) days of the date of receipt of the complete certification application by the department.

(D) The department shall issue a written notice of approval or disapproval of the certification application to the owner or operator within one hundred twenty (120) days of receipt of the complete certification application under clause (B). In the event the department does not issue such a notice within such one hundred twenty (120) day period, each monitoring system that meets the applicable performance requirements of 40 CFR 75* and is included in the certification application shall be deemed certified for use under the CAIR NOx ozone season trading program. The issuance of notices shall be as follows:

(i) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR 75*, then the department shall issue a written notice of approval of the certification application within one hundred twenty (120) days of receipt.

(ii) If the certification application is not complete, then the department shall issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the department may issue a notice of disapproval under item (iii). The one hundred twenty (120) day review period shall not begin before receipt of a complete certification application.

(iii) If the certification application shows that any monitoring system does not meet the performance requirements of 40 CFR 75* or if the certification application is incomplete and the requirement for disapproval under item (ii) is met, then the department shall issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the department and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification, as defined under 40 CFR 75.20(a)(3)*. The owner or operator shall follow the procedures for loss of certification in clause (E) for each monitoring system that is disapproved for initial certification.

(iv) The department or, for a CAIR NOx ozone season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet
issued or denied under section 12 of this rule, the U.S. EPA may issue a notice of disapproval of the certification status of a monitor in accordance with subsection (l).

(E) If the department or the U.S. EPA issues a notice of disapproval of a certification application under clause (D)(iii) or a notice of disapproval of certification status under clause (D)(iv), then the following shall apply:

(i) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under 40 CFR 75.20(a)(4)(iii)*, 40 CFR 75.20(g)(7)*, or 40 CFR 75.21(e)* and continuing until the applicable date and hour specified under 40 CFR 75.20(a)(5)(i)* or 40 CFR 75.20(g)(7)*:

(AA) For a disapproved NOx emission rate, NOx-diluent, system, the maximum potential NOx emission rate, as defined in 40 CFR 72.2*.

(BB) For a disapproved NOx pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NOx and the maximum potential flow rate, as defined in 40 CFR 75, Appendix A, Sections 2.1.2.1 and 2.1.4.1*.

(CC) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO2 concentration or the minimum potential O2 concentration, as applicable, as defined in 40 CFR 75, Appendix A, Sections 2.1.5, 2.1.3.1, and 2.1.3.2*.

(DD) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in 40 CFR 75, Appendix D, Section 2.4.2.1*.

(EE) For a disapproved excepted NOx ozone season monitoring system under 40 CFR 75, Appendix E, the fuel-specific maximum potential NOx ozone season emission rate, as defined in 40 CFR 72.2*.

(ii) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with clauses (A) and (B).

(iii) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the department's or the U.S. EPA's notice of disapproval, not later than thirty (30) unit operating days after the date of issuance of the notice of disapproval.

(i) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under 40 CFR 75.19* shall meet the applicable certification and recertification requirements in 40 CFR 75.19(a)(2)* and 40 CFR 75.20(h)*. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g)*.

(j) The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the U.S. EPA and, if applicable, the department under 40 CFR 75, Subpart E* shall comply with the applicable notification and application procedures of 40 CFR 75.20(f)*.

(k) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of 40 CFR 75*, data shall be substituted using the applicable missing data procedures in 40 CFR, Subpart D*, 40 CFR 75, Subpart H*, 40 CFR 75, Appendix D*, or 40 CFR 75, Appendix E*.

(l) Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under subsections (f) through (j) or the applicable provisions of 40 CFR 75*, both at the time of the initial certification or recertification application submission and at the time of the audit, the department or, for a CAIR NOx ozone season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under section 12 of this rule, the U.S. EPA will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this subsection and subsection (k), an audit shall be either a field audit or an audit of any information submitted to the department or the U.S. EPA. By issuing the notice of disapproval, the department or the U.S. EPA revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in subsections (f) through (j) for each disapproved monitoring system.

(m) The CAIR designated representative for a CAIR NOx ozone season unit shall submit written notice to the department and the U.S. EPA in accordance with 40 CFR 75.61*.
(n) The CAIR designated representative shall comply with all record keeping and reporting requirements in this subsection, the applicable record keeping and reporting requirements under 40 CFR 75.73*, and the requirements of section 6(e)(1) of this rule as follows:

1. The owner or operator of a CAIR NO\textsubscript{x} ozone season unit shall comply with requirements of 40 CFR 75.73(c)* and 40 CFR 75.73(e)* and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under section 12 of this rule.

2. The CAIR designated representative shall submit an application to the department within forty (45) days after completing all initial certification or recertification tests required under subsections (f) through (j), including the information required under 40 CFR 75.63*.

3. The CAIR designated representative shall submit quarterly reports as follows:

   A. If the CAIR NO\textsubscript{x} ozone season unit is subject to an acid rain emissions limitation or a CAIR NO\textsubscript{x} emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this section, the CAIR designated representative shall meet the requirements of 40 CFR 75, Subpart H*, concerning monitoring of NO\textsubscript{x} mass emissions, for such unit for the entire year and shall report the NO\textsubscript{x} mass emissions data and heat input data for such unit, in a format prescribed by the U.S. EPA, for each calendar quarter beginning with:

      i. for a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008, through June 30, 2008;
      ii. for a unit that commences commercial operation or on after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under subsection (c), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering May 1, 2008, through June 30, 2008;
      iii. notwithstanding items (i) and (ii), for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under section 12 of this rule, the calendar quarter corresponding to the date specified in section 12(f)(2), 12(f)(3), and 12(f)(4) of this rule; and
      iv. notwithstanding items (i) and (ii), for a CAIR NO\textsubscript{x} opt-in unit under section 12 of this rule, the calendar quarter corresponding to the date on which the CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} annual trading program as provided in section 12(f)(9) of this rule.

   B. If the CAIR NO\textsubscript{x} ozone season unit is not subject to an acid rain emissions limitation or a CAIR NO\textsubscript{x} emissions limitation, then the CAIR designated representative shall meet either of the following:

      i. Meet the requirements of 40 CFR 75, Subpart H*, concerning monitoring of NO\textsubscript{x} mass emissions, for such unit for the entire year and report the NO\textsubscript{x} mass emissions data and heat input data for such unit in accordance with clause (A).
      ii. Meet the requirements of 40 CFR 75, Subpart H* for the control period, including the requirements in 40 CFR 75.74(c)*, and report NO\textsubscript{x} mass emissions data and heat input data, including the data described in 40 CFR 75.74(c)(6)*, for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the U.S. EPA, for each calendar quarter beginning with:

         AA) for a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008, through June 30, 2008;
         BB) for a unit that commences commercial operation or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under subsection (c), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date;
         CC) notwithstanding subitems (AA) and (BB), for a unit for which a CAIR opt-in permit application submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under section 12 of this rule, the calendar quarter corresponding to the date specified in section 12(f)(2), 12(f)(3), and 12(f)(4) of this rule; and
         DD) notwithstanding items (i) and (ii), for a CAIR NO\textsubscript{x} opt-in unit under section 12 of this rule, the calendar quarter corresponding to the date on which the CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} annual trading program as provided in section 12(f)(9) of this rule.

   C. The CAIR designated representative shall submit each quarterly report to the U.S. EPA within thirty (30) days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in 40 CFR 75.73(f)*.
(D) For CAIR NOx ozone season units that are also subject to an acid rain emissions limitation or the CAIR NOx ozone season trading program, CAIR SO2 trading program, or mercury budget trading program, quarterly reports shall include the applicable data and information required by 40 CFR 75, Subparts F through I* as applicable, in addition to the NOx mass emission data, heat input data, and other information required by this subpart.

(4) The CAIR designated representative shall submit to the U.S. EPA a compliance certification, in a format prescribed by the U.S. EPA in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(A) the monitoring data submitted were recorded in accordance with the applicable requirements of this section and 40 CFR 75*, including the quality assurance procedures and specifications;
(B) for a unit with add-on NOx ozone season emission controls and for all hours where NOx data are substituted in accordance with 40 CFR 75.34(a)(1)*, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under 40 CFR 75, Appendix B* and the substitute data values do not systematically underestimate NOx emissions; and
(C) for a unit that is reporting on a control period basis under subdivision 3(B)(ii), the NOx mass emission rate and NOx concentration values substituted for missing data under 40 CFR 75, Subpart D* are calculated using only values from a control period and do not systemically underestimate NOx emissions.

(o) A petition requesting approval of alternatives to any requirement of this section may be made as follows:

(1) Except as provided in subdivision (3), the CAIR designated representative of a CAIR NOx ozone season unit that is subject to an acid rain emissions limitation may submit a petition under 40 CFR 75.66* to the U.S. EPA requesting approval to apply an alternative to any requirement of this section. Application of an alternative to any requirement of this section is in accordance with this section only to the extent that the petition is approved in writing by the U.S. EPA, in consultation with the department.

(2) The CAIR designated representative of a CAIR NOx ozone season unit that is not subject to an acid rain emissions limitation may submit a petition under 40 CFR 75.66* to the department and the U.S. EPA requesting approval to apply an alternative to any requirement of this section. Application of an alternative to any requirement of this section is in accordance with this section only to the extent that the petition is approved in writing by both the department and the U.S. EPA.

(3) The CAIR designated representative of a CAIR NOx ozone season unit that is subject to an acid rain emissions limitation may submit a petition under 40 CFR 75.66* to the department and the U.S. EPA requesting approval to apply an alternative to a requirement concerning any additional continuous emission monitoring system required under 40 CFR 75.72*. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the department and the U.S. EPA.

(p) The owner or operator of a CAIR NOx unit is subject to the applicable provisions of 40 CFR 75* concerning units in long-term cold storage.

*These documents are incorporated by reference. Copies may be obtained from the Government Printing Office, 732 North Capitol Street NW, Washington, D.C. 20401 or are available for review and copying at the Indiana Department of Environmental Management, Office of Air Quality, Indiana Government Center-North, Tenth Floor, 100 North Senate Avenue, Indianapolis, Indiana 46204. (Air Pollution Control Division; 326 IAC 24-3-11; filed Jan 26, 2007, 10:25 a.m.: 20070221-IR-326050117FRA)

326 IAC 24-3-12 CAIR NOx ozone season opt-in units (Repealed)

Sec. 12. (Repealed by Air Pollution Control Division; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

Rule 4. Clean Air Mercury Rule (CAMR) Trading Program (Repealed)
(Repealed by Air Pollution Control Division; filed Sep 19, 2014, 3:11 p.m.: 20141015-IR-326130488FRA)

Rule 5. Nitrogen Oxides (NOx) Annual Trading Program

326 IAC 24-5-1 Applicability and incorporation by reference

Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11

Affected: IC 4-22-9-5; IC 13-11-2; IC 13-15; IC 13-17
Sec. 1. (a) This rule applies to CSAPR NOx annual units and CSAPR NOx annual sources as specified in 40 CFR 97.404*, as amended by 81 FR 74605, that are located in Indiana.

(b) The definitions in IC 13-11-2, 326 IAC 1, and 40 CFR 97.402*, as amended by 84 FR 74604, apply throughout this rule. For purposes of this rule, the definition for a term provided in 40 CFR 97.402 controls in any conflict between 326 IAC 1 and 40 CFR 97.402.

(c) The following federal provisions are incorporated by reference:

(1) The CSAPR NOx Annual Trading Program at:

(A) 40 CFR 97.402* through 40 CFR 97.408*, as amended by 81 FR 74604;
(B) 40 CFR 97.411(c)(1)* through 40 CFR 97.411(c)(4)*, as amended by 81 FR 74606;
(C) 40 CFR 97.411(c)(5)(i)* and 40 CFR 97.411(c)(5)(ii)*, as amended by 81 FR 74606;
(D) 40 CFR 97.413* through 40 CFR 97.420*, as amended by 81 FR 74606;
(E) 40 CFR 97.421(e)* through 40 CFR 97.421(g)*, as amended by 81 FR 74606;
(F) 40 CFR 97.421(i)*, as amended by 81 FR 74606;
(G) 40 CFR 97.421(k)* and 40 CFR 97.421(l)*, as amended by 81 FR 74606; and

(2) The Indiana NOx annual variability limit at 40 CFR 97.410(b)(4)*, as amended by 81 FR 74606.

(d) The following are substitutions to 40 CFR as incorporated into this rule:

(1) As it appears in 40 CFR 97.402 and 40 CFR 97.406(c)(2)(iii), substitute the following:

(A) Delete "$ 97.410(a)" and insert "40 CFR 97.410(a)(4)(iv)*".
(B) Delete "$ 97.410(b)" and insert "40 CFR 97.410(b)(4)."

(2) As it appears in 40 CFR 97.402, delete "$ 97.411 and 97.412" and insert "326 IAC 24-5-5, 326 IAC 24-5-6, and 326 IAC 24-5-7."

(3) As it appears in 40 CFR 97.406(b)(2), delete "$ 97.411(a)(2) and (b) and 97.412" and insert "326 IAC 24-5-5, 326 IAC 24-5-6, and 326 IAC 24-5-7."

*These documents are incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204.

(Air Pollution Control Division; 326 IAC 24-5-2; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-5-3 CSAPR NOx annual allocation timing
Authority: IC 13-14-8; IC 13-17-3; IC 13-17-3-11
Affected: IC 13-14-9; IC 13-17-3-17

Sec. 3. The department shall allocate CSAPR NOx annual allowances according to the following schedule:

(1) By June 1, 2018, the department shall submit to the United States Environmental Protection Agency (U.S. EPA) the existing unit allowance allocations, in accordance with section 5 of this rule, for control periods in 2021 and 2022.

(2) By June 1, 2019, and June 1 every two (2) years thereafter, the department shall submit to U.S. EPA the existing unit allowance allocations in accordance with section 5 of this rule, for control periods four (4) and five (5) years after the applicable deadline for submission under this subdivision.
(3) By July 1, 2021, and July 1 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allowance allocations, in accordance with section 6 of this rule, for the control period in the year of the applicable deadline for submission under this subdivision.

(4) By February 6, 2022, and February 6 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allowance allocations in accordance with section 7 of this rule, for the control period in the previous year of the applicable deadline for submission under this subdivision.

326 IAC 24-5-4 Baseline heat input and historic emissions
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 4. (a) For purposes of this rule, an existing unit is any unit with a baseline heat input, in million British thermal units (MMBtu). Baseline heat input is determined as follows:

(1) If a unit commenced commercial operation prior to January 1, 2016, then the following applies:
   (A) For an allowance allocation for control periods in 2021 and 2022 the baseline heat input is the average of the three (3) highest control period heat inputs in 2008 through 2015.
   (B) For an allowance allocation for control periods in 2023 and 2024 and every two (2) control periods thereafter, the baseline heat input is the average of the three (3) highest, non-zero control period heat inputs in the eight (8) years before the allocation is calculated.
   (C) If a unit has only two (2) non-zero heat inputs during the eight (8) years before the allocation is calculated, the baseline heat input is the average of those two (2) non-zero control period heat inputs.
   (D) If a unit has only one (1) non-zero heat input during the eight (8) years before the allocation is calculated, the baseline heat input is that one (1) non-zero control period heat input.

(2) If a unit commenced commercial operation on or after January 1, 2016, and operates each control period during a period of three (3) or more consecutive calendar years, for an allowance allocation under section 3(2) of this rule, the baseline heat input is the average of the three (3) highest, non-zero control period heat input values for the years before the calculation of the allocation, not to exceed eight (8) control periods.

(b) For purposes of this rule, new units either:
   (1) commenced operation on or after January 1, 2016, and do not have a baseline heat input; or
   (2) did not receive allowances as determined under section 5(c) of this rule, and operated during the control period immediately preceding the year of allocation.

(c) The maximum historic emission cap is the maximum NOx emissions, in tons, that occurred during any control period of the historic emissions period. The historic emissions period is an eight (8) year history for each unit ending with the most recent year of the eight (8) years used for the determination of the heat input under subsection (a).

(d) A unit's control period heat input and a unit's total tons of NOx emissions during a control period under this section must be determined in accordance with 40 CFR 75*.

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-5-4; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-5-5 Existing unit allocations and adjustments
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 5. (a) For each control period in 2021 and thereafter, the department shall allocate to all existing units that have a baseline heat input the total amount of allowances as listed in section 2(c) of this rule in accordance with this section.

(b) The initial allocation for an existing unit is the existing unit budget multiplied by the ratio of the baseline heat input of the unit to the total amount of baseline heat inputs of all CSAPR NOx annual units, rounded to the nearest whole allowance.

(c) A unit receives no allowances if the unit does not operate during the control period in two (2) consecutive years as follows:
   (1) Allowances must not be allocated to the unit for the control period in the fifth year after the first year of not operating and in each year after the fifth year.
   (2) If the unit resumes operation, the department must allocate allowances to the unit in accordance with the standards for new unit allocations until the unit has a baseline heat input.
(d) The allocation to each unit is the lesser of the following, plus any reapportioned allowances:

1. Initial allocation under subsection (b).
2. A cap on emissions pursuant to a federally enforceable judicial consent decree.
3. Maximum historic emissions, as determined under section 4(c) of this rule.
4. No allowances if the unit does not operate as described in subsection (c).
(e) All allowances remaining after the application of subsections (b) and (c) are reapportioned as follows, until the entire existing unit budget is allocated, with each resulting allocation value rounded to the nearest whole allowance:

1. Remaining allowances are reapportioned to the remaining units whose initial allocation is not limited by subsection (d)(2) through (d)(4).
2. Allocations are apportioned on the same basis as under subsection (b).
3. These steps are repeated with each revised allocation distribution until the entire existing unit budget is allocated.

(f) By March 1 of each year existing unit allocations are made under this section, the department shall make the allowance allocations available for public review. The department may adjust each determination if appropriate or necessary to ensure that it is in accordance with this rule. (Air Pollution Control Division; 326 IAC 24-5-5, filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-5-6 New unit allocations
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 6. (a) For each control period in 2021 and thereafter, the department shall allocate to all new units, a total amount of allowances in the new unit set-aside as listed in section 2(b) of this rule.

(b) The department must determine for each new unit an allocation of allowances for the later of the following control periods and for each subsequent control period:

1. The control period starting in 2021.
2. The first full control period after the unit commences commercial operation.
3. For a unit misallocated allowances under 40 CFR 97.411(c)*, as amended by 81 FR 74606, the first control period in which the unit operates in Indiana after operating in another jurisdiction and the unit must not already have been allocated one (1) or more allowances.
4. For a unit that received no allowances as described in section 5(c) of this rule that resumes operation, the first full control period after the unit resumes operation.

(c) The allocation to each unit for each control period must be an amount equal to the unit's total tons of NOx emissions during the immediately preceding control period. The department may adjust the allocations as follows:

1. If the amount of allowances in the new unit set-aside for a control period is greater than or equal to the sum of the preceding control period emissions, then the department shall allocate the amount equal to the unit's total tons of NOx emissions during the immediately preceding control period.
2. If the amount of allowances in the new unit set-aside for a control period is less than the sum of the preceding control period emissions, then the department shall allocate to each unit an amount equal to the unit's tons of NOx emissions during the immediately preceding control period for the unit, multiplied by the amount of allowances in the new unit set-aside for the control period, divided by the sum of the preceding control period emissions, rounded to the nearest whole allowance.

(d) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section.

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-5-6; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-5-7 Unallocated new unit set-aside allowances
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 7. (a) Unallocated allowances remaining in the new unit set-aside after completion of the procedures of section 6 of this rule, for a control period, shall be allocated first to new units as follows:

1. For each unit that commenced commercial operation during the period starting January 1 of the year before the year of the control period and ending November 30 of the year of the control period, the department shall determine the positive difference, if any, between the unit's emissions during the control period and the amount of allowances awarded for the unit for the control period.
(2) The department shall determine the sum of the positive differences determined under subdivision (1) and then proceed as follows:

(A) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is greater than or equal to the sum determined under this subdivision, then the department must allocate the amount of allowances determined for each unit under subdivision (1).

(B) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is less than the sum under this subdivision, then the department must allocate to each unit under the following formula, rounded to the nearest whole allowance:

\[
\text{Unit allowance} = \frac{(E - A) \times \text{RNUSA}}{\text{Sum}}
\]

Where:
- Unit allowance is the total allowances allocated to the unit.
- \(E\) is the unit's emissions during the control period.
- \(A\) is the amount of allowances awarded for the unit for the control period.
- \(\text{RNUSA}\) is the remaining allowances in the new unit set-aside.
- \(\text{Sum}\) is the total amount of allocations under this subdivision.

(b) After completion of the procedures under subsection (a) for a control period, if any unallocated allowances remain in the new unit set-aside for the control period, the department shall allocate to each existing unit that was allocated allowances under section 5 of this rule, an amount of allowances under the following formula:

\[
\text{Unit allowance} = \frac{\text{UA} \times \text{EUA}}{\text{EUB}}
\]

Where:
- Unit allowance is the total allowances allocated to the unit.
- \(\text{UA}\) is the total amount of the remaining unallocated allowances in the new unit set-aside.
- \(\text{EUA}\) is the unit's allocation under section 5 of this rule for the control period.
- \(\text{EUB}\) is the existing unit budget, as listed in section 2(c) of this rule, for the control period, rounded to the nearest whole allowance.

(c) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section.

Rule 6. Nitrogen Oxides (NO\(_x\)) Ozone Season Group 2 Trading Program

326 IAC 24-6-1 Applicability and incorporation by reference

Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
AFFECTED: IC 4-22-9-5; IC 13-11-2; IC 13-15; IC 13-17

Sec. 1. (a) This rule applies to CSAPR NO\(_x\) Ozone Season Group 2 units and CSAPR NO\(_x\) Ozone Season Group 2 sources as specified in 40 CFR 97.804*, as added by 81 FR 74627, that are located in Indiana.

(b) The definitions in IC 13-11-2, 326 IAC 1, and 40 CFR 97.802*, as added by 81 FR 74622, apply throughout this rule. For purposes of this rule, the definition for a term provided in 40 CFR 97.802 controls in any conflict between 326 IAC 1 and 40 CFR 97.802.

(c) The following federal provisions are incorporated by reference:

(1) The CSAPR NO\(_x\), Ozone Season Group 2 Trading Program at:
- (A) 40 CFR 97.802* through 40 CFR 97.808*, as added by 81 FR 74622;
- (B) 40 CFR 97.811(c)(1)* through 40 CFR 97.811(c)(4)*, as added by 81 FR 74633;
- (C) 40 CFR 97.811(c)(5)(i)* and 40 CFR 97.811(c)(5)(ii)*, as added by 81 FR 74633;
- (D) 40 CFR 97.813* through CFR 97.820*, as added by 81 FR 74637;
- (E) 40 CFR 97.821(d)* through 40 CFR 97.411(g)*, as added by 81 FR 74642;
- (F) 40 CFR 97.821(i)*, as added by 81 FR 74642;
- (G) 40 CFR 97.821(k)* and 40 CFR 97.821(l)*, as added by 81 FR 74643; and
- (H) 40 CFR 97.822* through 40 CFR 97.835*, as added by 81 FR 74643.

(2) The Indiana NO\(_x\) ozone season group 2 variability limit at 40 CFR 97.810(b)(5)*, as added by 81 FR 74631.

(d) The following are substitutions to 40 CFR as incorporated into this rule:

(1) As it appears in 40 CFR 97.802 and 40 CFR 97.806(c)(2)(iii), substitute the following:
- (A) Delete "§ 97.810(a)" and insert "40 CFR 97.810(a)(5)(i)".
(B) Delete "§ 97.810(b)" and insert "40 CFR 97.810(b)(5)".

(2) As it appears in 40 CFR 97.802, delete "§ § 97.811 and 97.812" and insert "326 IAC 24-6-5, 326 IAC 24-6-6, and 326 IAC 24-6-7".

(3) As it appears in 40 CFR 97.806(b)(2), delete "§ § 97.811(a)(2) and (b) 97.812" and insert "326 IAC 24-6-5, 326 IAC 24-6-6, and 326 IAC 24-6-7".

*These documents are incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204.

(Air Pollution Control Division; 326 IAC 24-6-1; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-6-2 CSAPR NOx ozone season group 2 trading budget
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 2. (a) The total Indiana CSAPR NOx ozone season group 2 trading budget, in 40 CFR 97.810(a)(5)(i)*, as added by 81 FR 74631, is available for each control period starting in 2021 and thereafter. This does not include any tons in a variability limit.

(b) For each control period in 2021 and thereafter, a new unit set-aside is established for Indiana equal to the allowances at 40 CFR 97.810(a)(5)(ii)*, as added by 81 FR 74631, and any additional allowances at 40 CFR 97.811(c)(5)*, as added by 81 FR 74633.

(c) The existing unit budget is the difference between the total trading budget at 40 CFR 97.810(a)(5)(i)*, as added by 81 FR 74631, and the new unit set-aside at 40 CFR 97.810(a)(5)(ii)*, as added by 81 FR 74631.

*These documents are incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204.

(Air Pollution Control Division; 326 IAC 24-6-2; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-6-3 CSAPR NOx ozone season group 2 allocation timing
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 3. The department shall allocate CSAPR NOx ozone season group 2 allowances according to the following schedule:

1. By June 1, 2018, the department shall submit to U.S. EPA the existing unit allowance allocations, in accordance with section 5 of this rule, for control periods in 2021 and 2022.

2. By June 1, 2019, and June 1 every two (2) years thereafter, the department shall submit to U.S. EPA the existing unit allowance allocations in accordance with section 5 of this rule, for control periods four (4) and five (5) years after the applicable deadline for submission under this subdivision.

3. By July 1, 2021, and July 1 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allowance allocations, in accordance with section 6 of this rule, for the control period in the year of the applicable deadline for submission under this subdivision.

4. By February 6, 2022, and February 6 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allocation allocations in accordance with section 7 of this rule, for the control period in the previous year of the applicable deadline for submission under this subdivision.

(Air Pollution Control Division; 326 IAC 24-6-3; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-6-4 Baseline heat input and historic emissions
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 4. (a) For purposes of this rule, an existing unit is any unit with a baseline heat input, in MMBtu. Baseline heat input is determined as follows:

1. If a unit commenced commercial operation prior to January 1, 2016, then the following applies:

(A) For an allowance allocation for control periods in 2021 and 2022 the baseline heat input is the average of the three (3) highest control period heat inputs in 2008 through 2015.

(B) For an allowance allocation for control periods in 2023 and 2024 and every two (2) control periods thereafter, the baseline heat input is the average of the three (3) highest, non-zero control period heat inputs in the eight (8) years before the allocation is calculated.
(C) If a unit has only two (2) non-zero heat inputs during the eight (8) years before the allocation is calculated, the baseline heat input is the average of those two (2) non-zero control period heat inputs. 

(D) If a unit has only one (1) non-zero heat input during the eight (8) years before the allocation is calculated, the baseline heat input is that one (1) non-zero control period heat input. 

(2) If a unit commenced commercial operation on or after January 1, 2016, and operates each control period during a period of three (3) or more consecutive calendar years, for an allowance allocation under section 3(2) of this rule, the baseline heat input is the average of the three (3) highest, non-zero control period heat input values for the years before the calculation of the allocation, not to exceed eight (8) control periods. 

(b) For purposes of this rule, new units either: 

(1) commenced operation on or after January 1, 2016, and do not have a baseline heat input; or 

(2) did not receive allowances as determined under section 5(c) of this rule, and operated during the control period immediately preceding the year of allocation. 

(c) The maximum historic emission cap is the maximum NO\textsubscript{x} emissions, in tons, that occurred during any control period of the historic emissions period. The historic emissions period is an eight (8) year history for each unit ending with the most recent year of the eight (8) years used for the determination of the heat input under subsection (a). 

(d) A unit's control period heat input and a unit's total tons of NO\textsubscript{x} emissions during a control period under this section must be determined in accordance with 40 CFR 75*. 

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-6-4; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA) 

326 IAC 24-6-5 Existing unit allocations and adjustments 

Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11 

Affected: IC 13-15; IC 13-17 

Sec. 5. (a) For each control period in 2021 and thereafter, the department shall allocate to all existing units that have a baseline heat input the total amount of allowances as listed in section 2(c) of this rule in accordance with this section. 

(b) The initial allocation for an existing unit is the existing unit budget multiplied by the ratio of the baseline heat input of the unit to the total amount of baseline heat inputs of all CSAPR NO\textsubscript{x} ozone season group 2 units, rounded to the nearest whole allowance. 

(c) A unit receives no allowances if the unit does not operate during the control period in two (2) consecutive years as follows: 

(1) Allowances must not be allocated to the unit for the control period in the fifth year after the first year of not operating and in each year after the fifth year. 

(2) If the unit resumes operation, the department must allocate allowances to the unit in accordance with the standards for new unit allocations until the unit has a baseline heat input. 

(d) The allocation to each unit is the lesser of the following, plus any reapportioned allowances: 

(1) Initial allocation under subsection (b). 

(2) A cap on emissions pursuant to a federally enforceable judicial consent decree. 

(3) Maximum historic emissions, as determined under section 4(c) of this rule. 

(4) No allowances if the unit does not operate as described in subsection (c). 

(e) All allowances remaining after the application of subsections (b) and (c) are reapportioned as follows, until the entire existing unit budget is allocated, with each resulting allocation value rounded to the nearest whole allowance: 

(1) Remaining allowances are reapportioned to the remaining units whose initial allocation is not limited by subsection (d)(2) through (d)(4). 

(2) Allocations are apportioned on the same basis as under subsection (b). 

(3) These steps are repeated with each revised allocation distribution until the entire existing unit budget is allocated. 

(f) By March 1 of each year existing unit allocations are made under this section, the department shall make the allowance allocations available for public review. The department may adjust each determination if appropriate or necessary to ensure that it is in accordance with this rule. (Air Pollution Control Division; 326 IAC 24-6-5; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA) 

326 IAC 24-6-6 New unit allocations 

Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11 

Affected: IC 4-22-9-5; IC 13-15; IC 13-17
Attachment F

Sec. 6. (a) For each control period in 2021 and thereafter, the department shall allocate to all new units, a total amount of allowances in the new unit set-aside as listed in section 2(b) of this rule.

(b) The department must determine for each new unit an allocation of allowances for the later of the following control periods and for each subsequent control period:

1. The control period starting in 2021.
2. The first full control period after the unit commences commercial operation.
3. For a unit misallocated allowances under 40 CFR 97.811(c)*, as added by 81 FR 74633, the first control period in which the unit operates in Indiana after operating in another jurisdiction and the unit must not already have been allocated one (1) or more allowances.
4. For a unit that received no allowances as described in section 5(c) of this rule that resumes operation, the first full control period after the unit resumes operation.

(c) The allocation to each unit for each control period must be an amount equal to the unit's total tons of NOx emissions during the immediately preceding control period. The department may adjust the allocations as follows:

1. If the amount of allowances in the new unit set-aside for a control period is greater than or equal to the sum of the preceding control period emissions, then the department shall allocate the amount equal to the unit's total tons of NOx emissions during the immediately preceding control period.
2. If the amount of allowances in the new unit set-aside for a control period is less than the sum of the preceding control period emissions, then the department shall allocate to each unit an amount equal to the unit's tons of NOx emissions during the immediately preceding control period, divided by the amount of allowances in the new unit set-aside for the control period, multiplied by the sum of the preceding control period emissions, rounded to the nearest whole allowance.

(d) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section.

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-6-6; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-6-7 Unallocated new unit set-aside allowances

Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11

Sec. 7. (a) Unallocated allowances remaining in the new unit set-aside after completion of the procedures of section 6 of this rule, for a control period, shall be allocated first to new units as follows:

1. For each unit that commenced commercial operation during the period starting January 1 of the year before the year of the control period and ending November 30 of the year of the control period, the department shall determine the positive difference, if any, between the unit's emissions during the control period and the amount of allowances awarded for the unit for the control period.

2. The department shall determine the sum of the positive differences determined under subdivision (1) and then proceed as follows:

(A) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is greater than or equal to the sum determined under this subdivision, then the department must allocate the amount of allowances determined for each unit under subdivision (1).

(B) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is less than the sum under this subdivision, then the department must allocate to each unit the following formula, rounded to the nearest whole allowance:

\[ \text{Unit Allowance} = \frac{(E - A) \times \text{RNUSA}}{\text{Sum}} \]

Where:
- Unit allowance is the total allowances allocated to the unit.
- \( E \) is the unit's emissions during the control period.
- \( A \) is the amount of allowances awarded for the unit for the control period.
- RNUSA is the remaining allowances in the new unit set-aside.
- Sum is the total amount of allocations under this subdivision.

(b) After completion of the procedures under subsection (a) for a control period, if any unallocated allowances remain in the new unit set-aside for the control period, the department shall allocate to each existing unit that was allocated allowances under section 5 of this rule, an amount of allowances under the following formula:
Unit allowance = \( \frac{(UA \times EUA)}{EUB} \)

Where:
- Unit allowance is the total allowances allocated to the unit.
- UA is the total amount of the remaining unallocated allowances in the new unit set-aside.
- EUA is the unit's allocation under section 5 of this rule for the control period.
- EUB is the existing unit budget, as listed in section 2(c) of this rule, for the control period, rounded to the nearest whole allowance.

(c) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section. (Air Pollution Control Division; 326 IAC 24-6-7; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

**Rule 7. Sulfur Dioxide (SO₂) Group 1 Trading Program**

**326 IAC 24-7-1 Applicability and incorporation by reference**

Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11

Affected: IC 4-22-9-5; IC 13-11-2; IC 13-15; IC 13-17

Sec. 1. (a) This rule applies to CSAPR SO₂ Group 1 units and CSAPR SO₂ Group 1 sources as specified in 40 CFR 97.604*, as amended by 81 FR 74616, that are located in Indiana.

(b) The definitions in IC 13-11-2, 326 IAC 1, and 40 CFR 97.602*, as amended by 81 FR 74615, apply throughout this rule. For purposes of this rule, the definition for a term provided in 40 CFR 97.602 controls in any conflict between 326 IAC 1 and 40 CFR 97.602.

(c) The following federal provisions are incorporated by reference:

(1) The CSAPR SO₂ Group 1 Trading Program at:
   - (A) 40 CFR 97.602* through 40 CFR 97.608*, as amended by 81 FR 74616;
   - (B) 40 CFR 97.611(c)(1)* through 40 CFR 97.611(c)(4)*, as amended by 81 FR 74616;
   - (C) 40 CFR 97.611(c)(5)(i)* and 40 CFR 97.611(c)(5)(ii)*, as amended by 81 FR 74616;
   - (D) 40 CFR 97.613* through 40 CFR 97.620*, as amended by 81 FR 74617;
   - (E) 40 CFR 97.621(e)* through 40 CFR 97.621(g)*, as amended by 81 FR 74617;
   - (F) 40 CFR 97.621(i)*, as amended by 81 FR 74617;
   - (G) 40 CFR 97.621(k)* and 40 CFR 97.621(l)*, as amended by 81 FR 74617; and
   - (H) 40 CFR 97.622* through 40 CFR 97.635*, as amended by 81 FR 74617.

(2) The Indiana CSAPR SO₂ group 1 trading budget variability limit at 40 CFR 97.610(b)(2)*, as amended by 81 FR 74616.

(d) The following are substitutions to 40 CFR as incorporated into this rule:

(1) As it appears in 40 CFR 97.602 and 40 CFR 97.606(c)(2)(iii) substitute the following:
   - (A) Delete "§ 97.610(a)" and insert "40 CFR 97.610(a)(2)(iv)".
   - (B) Delete "§ 97.610(b)" and insert "40 CFR 97.610(b)(2)".

(2) As it appears in 40 CFR 97.602, delete "§ 97.611 and 97.612" and insert "326 IAC 24-7-5, 326 IAC 24-7-6, and 326 IAC 24-7-7".

(3) As it appears in 40 CFR 97.606(b)(2), delete "§ 97.611(a)(2) and 97.611(b)" and insert "326 IAC 24-7-5, 326 IAC 24-7-6, and 326 IAC 24-7-7".

*These documents are incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-7-1; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

**326 IAC 24-7-2 CSAPR SO₂ group 1 trading budget**

Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11

Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 2. (a) The Indiana CSAPR SO₂ group 1 allowance trading budget, at 40 CFR 97.610(a)(2)(iv)*, as amended by 81 FR 74616, is available for each control period starting in 2021 and thereafter. This does not include any tons in a variability limit.

(b) For each control period in 2021 and thereafter, a new unit set-aside is established for Indiana equal to the allowances at 40 CFR 97.610(a)(2)(v)*, as amended by 81 FR 74616 and any additional allowances at 40 CFR 97.611(c)(5)*, as amended by 81 FR 74616.
(c) The existing unit budget is the difference between the total trading budget at 40 CFR 97.610(a)(2)(iv)*, as amended by 81 FR 74616, and the new unit set-aside at 40 CFR 97.610(a)(2)(v)*, as amended by 81 FR 74616.

*These documents are incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204.

(Air Pollution Control Division; 326 IAC 24-7-2; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-7-3 CSAPR SO₂ group 1 allocation timing
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 3. The department shall allocate CSAPR SO₂ group 1 allowances according to the following schedule:
(1) By June 1, 2018, the department shall submit to U.S. EPA the existing unit allowance allocations, in accordance with section 5 of this rule, for control periods in 2021 and 2022.
(2) By June 1, 2019, and June 1 every two (2) years thereafter, the department shall submit to U.S. EPA the existing unit allowance allocations in accordance with section 5 of this rule, for control periods four (4) and five (5) years after the applicable deadline for submission under this subdivision.
(3) By July 1, 2021, and July 1 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allowance allocations, in accordance with section 6 of this rule, for the control period in the year of the applicable deadline for submission under this subdivision.
(4) By February 6, 2022, and February 6 of each year thereafter, the department shall submit to U.S. EPA the new unit set-aside allowance allocations in accordance with section 7 of this rule, for the control period in the previous year of the applicable deadline for submission under this subdivision.

(Air Pollution Control Division; 326 IAC 24-7-3; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-7-4 Baseline heat input and historic emissions
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 4. (a) For purposes of this rule, an existing unit is any unit with a baseline heat input, in MMBtu. Baseline heat input is determined as follows:
(1) If a unit commenced commercial operation prior to January 1, 2016, then the following applies:
(A) For an allowance allocation for control periods in 2021 and 2022 the baseline heat input is the average of the three (3) highest control period heat inputs in 2008 through 2015.
(B) For an allowance allocation for control periods in 2023 and 2024 and every two (2) control periods thereafter, the baseline heat input is the average of the three (3) highest, non-zero control period heat inputs in the eight (8) years before the allocation is calculated.
(C) If a unit has only two (2) non-zero heat inputs during the eight (8) years before the allocation is calculated, the baseline heat input is the average of those two (2) non-zero control period heat inputs.
(D) If a unit has only one (1) non-zero heat input during the eight (8) years before the allocation is calculated, the baseline heat input is that one (1) non-zero control period heat input.
(2) If a unit commenced commercial operation on or after January 1, 2016, and operates each control period during a period of three (3) or more consecutive calendar years, for an allowance allocation under section 3(2) of this rule, the baseline heat input is the average of the three (3) highest, non-zero control period heat input values for the years before the calculation of the allocation, not to exceed eight (8) control periods.

(b) For purposes of this rule, new units either:
(1) commenced operation on or after January 1, 2016, and do not have a baseline heat input; or
(2) did not receive allowances as determined under section 5(c) of this rule, and operated during the control period immediately preceding the year of allocation.

(c) The maximum historic emission cap is the maximum SO₂ emissions, in tons, that occurred during any control period of the historic emissions period. The historic emissions period is an eight (8) year history for each unit ending with the most recent year of the eight (8) years used for the determination of the heat input under subsection (a).

(d) A unit’s control period heat input and a unit’s total tons of SO₂ emissions during a control period under this section must be determined in accordance with 40 CFR 75*.

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-7-4; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)
326 IAC 24-7-5 Existing unit allocations and adjustments
Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 5. (a) For each control period in 2021 and thereafter, the department shall allocate to all existing units that have a baseline heat input the total amount of allowances as listed in section 2(c) of this rule in accordance with this section.

(b) The initial allocation for an existing unit is the existing unit budget multiplied by the ratio of the baseline heat input of the unit to the total amount of baseline heat inputs of all CSAPR SO₂ group 1 units, rounded to the nearest whole allowance.

(c) A unit receives no allowances if the unit does not operate during the control period in two (2) consecutive years as follows:

(1) Allowances must not be allocated to the unit for the control period in the fifth year after the first year of not operating and in each year after the fifth year.

(2) If the unit resumes operation, the department must allocate allowances to the unit in accordance with the standards for new unit allocations until the unit has a baseline heat input.

(d) The allocation to each unit is the lesser of the following, plus any reapportioned allowances:

(1) Initial allocation under subsection (b).

(2) A cap on emissions pursuant to a federally enforceable judicial consent decree.

(3) Maximum historic emissions, as determined under section 4(c) of this rule.

(4) No allowances if the unit does not operate as described in subsection (c).

(e) All allowances remaining after the application of subsections (b) and (c) are reapportioned as follows, until the entire existing unit budget is allocated, with each resulting allocation value rounded to the nearest whole allowance:

(1) Remaining allowances are reapportioned to the remaining units whose initial allocation is not limited by subsection (d)(2) through (d)(4).

(2) Allocations are apportioned on the same basis as under subsection (b).

(3) These steps are repeated with each revised allocation distribution until the entire existing unit budget is allocated.

(f) By March 1 of each year existing unit allocations are made under this section, the department shall make the allowance allocations available for public review. The department may adjust each determination if appropriate or necessary to ensure that it is in accordance with this rule. (Air Pollution Control Division; 326 IAC 24-7-5; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-7-6 New unit allocations
Authority: IC 4-22-2-21; IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 4-22-9-5; IC 13-15; IC 13-17

Sec. 6. (a) For each control period in 2021 and thereafter, the department shall allocate to all new units, a total amount of allowances in the new unit set-aside as listed in section 2(b) of this rule.

(b) The department must determine for each new unit an allocation of allowances for the later of the following control periods and for each subsequent control period:

(1) The control period starting in 2021.

(2) The first full control period after the unit commences commercial operation.

(3) For a unit misallocated allowances under 40 CFR 97.611(c)*, as amended by 81 FR 74616, the first control period in which the unit operates in Indiana after operating in another jurisdiction and the unit must not already have been allocated one (1) or more allowances.

(4) For a unit that received no allowances as described in section 5(c) of this rule that resumes operation, the first full control period after the unit resumes operation.

(c) The allocation to each unit for each control period must be an amount equal to the unit's total tons of SO₂ emissions during the immediately preceding control period. The department may adjust the allocations as follows:

(1) If the amount of allowances in the new unit set-aside for a control period is greater than or equal to the sum of the preceding control period emissions, then the department shall allocate the amount equal to the unit's total tons of SO₂ emissions during the immediately preceding control period.

(2) If the amount of allowances in the new unit set-aside for a control period is less than the sum of the preceding control period emissions, then the department shall allocate to each unit an amount equal to the unit's tons of SO₂ emissions during the immediately preceding control period for the unit, multiplied by the amount of allowances in the new unit set-aside for the control period, divided by the sum of the preceding control period emissions, rounded to the nearest whole allowance.
(d) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section.

*This document is incorporated by reference. Copies may be obtained from the Government Publishing Office, www.gpo.gov, or are available for review at the Indiana Department of Environmental Management, Office of Legal Counsel, Indiana Government Center North, 100 North Senate Avenue, Thirteenth Floor, Indianapolis, IN 46204. (Air Pollution Control Division; 326 IAC 24-7-6; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)

326 IAC 24-7-7 Unallocated new unit set-aside allowances

Authority: IC 13-14-8; IC 13-17-3-4; IC 13-17-3-11
Affected: IC 13-15; IC 13-17

Sec. 7. (a) Unallocated allowances remaining in the new unit set-aside after completion of the procedures of section 6 of this rule, for a control period, shall be allocated first to new units as follows:

(1) For each unit that commenced commercial operation during the period starting January 1 of the year before the year of the control period and ending November 30 of the year of the control period, the department shall determine the positive difference, if any, between the unit's emissions during the control period and the amount of allowances awarded for the unit for the control period.

(2) The department shall determine the sum of the positive differences determined under subdivision (1) and then proceed as follows:

(A) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is greater than or equal to the sum determined under this subdivision, then the department must allocate the amount of allowances determined for each unit under subdivision (1).

(B) If the amount of unallocated allowances remaining in the new unit set-aside for a control period is less than the sum under this subdivision, then the department must allocate to each unit under the following formula, rounded to the nearest whole allowance:

\[
\text{Unit Allowance} = \frac{((E - A) \times \text{RNUSA})}{\text{Sum}}
\]

Where:
- Unit allowance is the total allowances allocated to the unit.
- E is the unit's emissions during the control period.
- A is the amount of allowances awarded for the unit for the control period.
- RNUSA is the remaining allowances in the new unit set-aside.
- Sum is the total amount of allocations under this subdivision.

(b) After completion of the procedures under subsection (a) for a control period, if any unallocated allowances remain in the new unit set-aside for the control period, the department shall allocate to each existing unit that was allocated allowances under section 5 of this rule, an amount of allowances under the following formula:

\[
\text{Unit allowance} = \frac{(\text{UA} \times \text{EUA})}{\text{EUB}}
\]

Where:
- Unit allowance is the total allowances allocated to the unit.
- UA is the total amount of the remaining unallocated allowances in the new unit set-aside.
- EUA is the unit's allocation under section 5 of this rule for the control period.
- EUB is the existing unit budget, as listed in section 2(c) of this rule, for the control period, rounded to the nearest whole allowance.

(c) The department shall notify each CSAPR designated representative of the amount of allowances allocated under this section. (Air Pollution Control Division; 326 IAC 24-7-7; filed Oct 25, 2017, 1:02 p.m.: 20171122-IR-326160209FRA)
IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA

Plaintiff,

and

STATE OF NEW YORK, ET AL.,

Plaintiff-Intervenors,

v.

AMERICAN ELECTRIC POWER SERVICE CORP., ET AL.,

Defendants.

Consolidated Cases:
Civil Action No. C2-99-1182
Civil Action No. C2-99-1250
JUDGE EDMUND A. SARGUS, JR.
Magistrate Judge Kimberly A. Jolson

OHIO CITIZEN ACTION, ET AL.,

Plaintiffs,

v.

AMERICAN ELECTRIC POWER SERVICE CORP., ET AL.,

Defendants.

Civil Action No. C2-04-1098
JUDGE EDMUND A. SARGUS, JR.
Magistrate Judge Kimberly A. Jolson

UNITED STATES OF AMERICA

Plaintiff,

v.

AMERICAN ELECTRIC POWER SERVICE CORP., ET AL.,

Defendants.

Civil Action No. C2-05-360
JUDGE EDMUND A. SARGUS, JR.
Magistrate Judge Kimberly A. Jolson
ORDER

This matter came before the Court on the Parties’ Joint Motion to Enter the Fifth Joint Modification of Consent Decree (ECF No.). Having reviewed the submissions of all Parties and being fully advised of the positions therein, the Court hereby GRANTS the Joint Motion and ORDERS that the following Paragraphs of the Consent Decree entered in this case are modified as set forth herein.

IT IS SO ORDERED.

[Signature]

7-17-2019

DATE

EDMUND A. SARGUS, JR.
CHIEF UNITED STATES DISTRICT JUDGE
FIFTH JOINT MODIFICATION TO
CONSENT DEGREE WITH ORDER MODIFYING CONSENT DEGREE

WHEREAS, On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS, Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS, pursuant to Paragraph 87 of the Consent Decree (Case No. 99-1250, Docket # 363), as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Case No. 99-1250, Docket # 371), as modified by a Second Joint Modification to Consent Decree with Order Modifying Consent Decree filed on December 28, 2010 (Case No. 99-1250, Docket # 372), as modified by a Third Joint Modification With Order Modifying Consent Decree filed on May 14, 2013 (Case No. 99-1182, Docket # 548), and as modified by an Agreed Entry Approving Fourth Joint Modification to Consent Decree filed on January 23, 2017 (Case No. 99-1182, Docket # 553), no later than December 31, 2025, the American Electric Power (AEP) Defendants are required, inter alia, to install and continuously operate a Flue Gas Desulfurization (FGD) system on, or Retire, Refuel, or Re-Power one Unit at the Rockport Plant, and no later than December 31, 2028, the AEP Defendants are required to install and continuously operate a FGD system on, or Retire, Refuel, or Re-Power the second Unit at the Rockport Plant.

WHEREAS, the AEP Defendants filed a Motion for Fifth Modification of Consent Decree in Case No. 99-1182 on July 21, 2017 (Case No. 99-1182, Docket # 555) and in the related cases seeking to further modify the provisions of Paragraph 87 and make other changes.

WHEREAS, the United States, the States, and Citizen Plaintiffs filed memoranda in
opposition to the motion by the AEP Defendants (Case No. 99-1182, Docket # 571 and 572, and Case No. 99-1250, Docket # 405) on September 1, 2017.

WHEREAS, the Parties made additional supplemental filings and engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Fifth Joint Modification finds, that this Fifth Joint Modification has been negotiated in good faith and at arm’s length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, et seq.; and that entry of this Fifth Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Fifth Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Fifth Joint Modification in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Fifth Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Fifth Joint Modification by this Court or challenge any provision of this Fifth Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Fifth Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Motion or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:
Modify the provisions of the Consent Decree, as amended by the first four modifications, as follows:

Add a new Paragraph 5A that states:

5A. A “30-Day Rolling Average Emission Rate” for Rockport means, and shall be expressed as, lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the combined Rockport stack during a Day which is an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; second, sum the total heat input to both Rockport Units in mmBTU during the Day which was an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Days which were Operating Days for either or both Rockport Units by the total heat input during the thirty such Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Day which is an Operating Day for either or both Rockport Units. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs from both Rockport Units that occur during a period of Malfunction at either Rockport Unit shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NOx and BTU inputs from both Rockport Units that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a single Rockport Unit during any 30-Day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a
violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR at the Unit in question in accordance with manufacturers' specifications and good engineering practices. A “Cold Start Up Period” occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NOx emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) at a single unit shall be the lesser of (i) those NOx emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NOx emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and c. For SO2, shall include all emissions and BTUs commencing from the time a single Rockport Unit is synchronized with a utility electric distribution system through the time that both Rockport Units cease to combust fossil fuel and the fire is out in both boilers.

Paragraph 14 is replaced in its entirety and now reads as follows:

14. “Continuously Operate” or “Continuous Operation” means that when an SCR, FGD, DSI, Enhanced DSI, ESP or other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.
Add a new Paragraph 20A that states:

20A. "Enhanced Dry Sorbent Injection" or "Enhanced DSI" means a pollution control system in which a dry sorbent is injected into the flue gas prior to the NOx and particulate matter controls in order to provide additional mixing and improved SO2 removal as compared to Dry Sorbent Injection.

Paragraph 67 is replaced in its entirety and now reads as follows:

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit NOx in excess of the following Eastern System-Wide Annual Tonnage Limitations:

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Eastern System-Wide Annual Tonnage Limitations for NOx</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>96,000 tons</td>
</tr>
<tr>
<td>2010</td>
<td>92,500 tons</td>
</tr>
<tr>
<td>2011</td>
<td>92,500 tons</td>
</tr>
<tr>
<td>2012</td>
<td>85,000 tons</td>
</tr>
<tr>
<td>2013</td>
<td>85,000 tons</td>
</tr>
<tr>
<td>2014</td>
<td>85,000 tons</td>
</tr>
<tr>
<td>2015</td>
<td>75,000 tons</td>
</tr>
<tr>
<td>2016-2017</td>
<td>72,000 tons per year</td>
</tr>
<tr>
<td>2018-2020</td>
<td>62,000 tons per year</td>
</tr>
<tr>
<td>2021-2028</td>
<td>52,000 tons per year</td>
</tr>
<tr>
<td>2029 and each year thereafter</td>
<td>44,000 tons per year</td>
</tr>
</tbody>
</table>

Paragraph 68 is replaced in its entirety and now reads as follows:

68. No later than the dates set forth in the table below, Defendants shall install and
Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-Power such Unit:

<table>
<thead>
<tr>
<th>Unit</th>
<th>NOx Pollution Control</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amos Unit 1</td>
<td>SCR</td>
<td>January 1, 2008</td>
</tr>
<tr>
<td>Amos Unit 2</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Amos Unit 3</td>
<td>SCR</td>
<td>January 1, 2008</td>
</tr>
<tr>
<td>Big Sandy Unit 2</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Cardinal Unit 1</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Cardinal Unit 2</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Cardinal Unit 3</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Conesville Unit 1</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>Date of Entry of this Consent Decree</td>
</tr>
<tr>
<td>Conesville Unit 2</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>Date of Entry of this Consent Decree</td>
</tr>
<tr>
<td>Conesville Unit 3</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>December 31, 2012</td>
</tr>
<tr>
<td>Conesville Unit 4</td>
<td>SCR</td>
<td>December 31, 2010</td>
</tr>
<tr>
<td>Gavin Unit 1</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Gavin Unit 2</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Mitchell Unit 1</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Mitchell Unit 2</td>
<td>SCR</td>
<td>January 1, 2009</td>
</tr>
<tr>
<td>Mountaineer Unit 1</td>
<td>SCR</td>
<td>January 1, 2008</td>
</tr>
<tr>
<td>Muskingum River Units 1-4</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>December 31, 2015</td>
</tr>
<tr>
<td>Muskingum River Unit 5</td>
<td>SCR</td>
<td>January 1, 2008</td>
</tr>
<tr>
<td>Rockport Unit 1</td>
<td>SCR</td>
<td>December 31, 2017</td>
</tr>
<tr>
<td>Rockport Unit 2</td>
<td>SCR</td>
<td>June 1, 2020</td>
</tr>
<tr>
<td>Sporn Unit 5</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>December 31, 2013</td>
</tr>
<tr>
<td>A total of at least 600 MW</td>
<td>Retire, Retrofit, or Re-Power</td>
<td>December 31, 2018</td>
</tr>
<tr>
<td>from the following list of</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Units: Sporn Units 1-4,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clinch River units 1-3,</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tanners Creek Units 1-3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>and/or Kammer Units 1-3</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Add a new Paragraph 68A that reads as follows:

68A. 30-Day Rolling Average NOx Emission Rate at Rockport. Beginning on the thirtieth Day which is an Operating Day for either one or both Rockport Units in calendar year 2021, average
NOx emissions from the Rockport Units shall be limited to 0.090 lb/mmBTU on a 30-day Rolling Average Basis at the combined stack for the Rockport Units. Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B.

Add a new Paragraph 68B that reads as follows:

68B. Informational NOx Monitoring. During the ozone seasons (May 1 – September 30) in each of calendar years 2019 and 2020, prior to the effective date of the 30-Day Rolling Average NOx Rate at the Rockport Units in Paragraph 68A, the AEP Defendants shall provide an estimate of the 30-day rolling average NOx emissions from Rockport Unit 1, based on NOx concentrations and percent CO₂ measured at an uncertified NOx monitor in the duct from Unit 1 before the flue gases from Rockport Units 1 and 2 combine at the common stack. Hourly NOx rates shall be calculated for each hour for which valid data is available, using the following equation:

\[
\text{NOx lb/mmBtu} = \left[ (1.194 \times 10^{-7}) \times \text{NOx ppm x 1840 scf CO₂ per mmBtu x 100} \right] / \% CO₂
\]

The monitor shall be calibrated daily and maintained in accordance with good engineering and maintenance practices. If valid NOx or CO₂ data is not available for any hour, that hour shall not be used in the calculation of the informational data provided to Plaintiffs, including periods of monitor downtime, calibrations, and maintenance. For informational purposes only, NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for May – June shall be reported to Plaintiffs by July 30, and NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for July – September shall be reported to Plaintiffs by October 30. Nothing in this Paragraph shall be construed to establish a Unit-specific NOx Emission Rate for Rockport Unit 1, and these interim reporting obligations are not required to be incorporated into the Title V permit for the Rockport Plant.
Paragraph 86 is replaced in its entirety and now reads as follows:

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO₂ in excess of the following Eastern System-Wide Annual Tonnage Limitations:

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Eastern System-Wide Annual Tonnage Limitations for SO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>450,000 tons</td>
</tr>
<tr>
<td>2011</td>
<td>450,000 tons</td>
</tr>
<tr>
<td>2012</td>
<td>420,000 tons</td>
</tr>
<tr>
<td>2013</td>
<td>350,000 tons</td>
</tr>
<tr>
<td>2014</td>
<td>340,000 tons</td>
</tr>
<tr>
<td>2015</td>
<td>275,000 tons</td>
</tr>
<tr>
<td>2016</td>
<td>145,000 tons</td>
</tr>
<tr>
<td>2017</td>
<td>145,000 tons</td>
</tr>
<tr>
<td>2018</td>
<td>145,000 tons</td>
</tr>
<tr>
<td>2019-2020</td>
<td>113,000 tons per year</td>
</tr>
<tr>
<td>2021-2028</td>
<td>94,000 tons per year</td>
</tr>
<tr>
<td>2029, and each year thereafter</td>
<td>89,000 tons per year</td>
</tr>
</tbody>
</table>

Paragraph 87 is replaced in its entirety and now reads as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD, Dry Sorbent Injection, or Enhanced Dry Sorbent Injection system on each Unit identified therein, or, if indicated in the table, Cease Burning Coal, Retire,
Retrofit, Re-power, or Refuel such Unit:

<table>
<thead>
<tr>
<th>Unit</th>
<th>SO₂ Pollution Control</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amos Unit 1</td>
<td>FGD</td>
<td>February 15, 2011</td>
</tr>
<tr>
<td>Amos Unit 2</td>
<td>FGD</td>
<td>April 2, 2010</td>
</tr>
<tr>
<td>Amos Unit 3</td>
<td>FGD</td>
<td>December 31, 2009</td>
</tr>
<tr>
<td>Big Sandy Unit 2</td>
<td>Retrofit, Retire, Re-Power or Refuel</td>
<td>December 31, 2015</td>
</tr>
<tr>
<td>Cardinal Units 1 and 2</td>
<td>FGD</td>
<td>December 31, 2008</td>
</tr>
<tr>
<td>Cardinal Unit 3</td>
<td>FGD</td>
<td>December 31, 2012</td>
</tr>
<tr>
<td>Conesville Units 1 and 2</td>
<td>Retire, Retrofit, or Re-power</td>
<td>Date of Entry</td>
</tr>
<tr>
<td>Conesville Unit 3</td>
<td>Retire, Retrofit, or Re-power</td>
<td>December 31, 2012</td>
</tr>
<tr>
<td>Conesville Unit 4</td>
<td>FGD</td>
<td>December 31, 2010</td>
</tr>
<tr>
<td>Conesville Unit 5</td>
<td>Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency</td>
<td>December 31, 2009</td>
</tr>
<tr>
<td>Conesville Unit 6</td>
<td>Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency</td>
<td>December 31, 2009</td>
</tr>
<tr>
<td>Gavin Units 1 and 2</td>
<td>FGD</td>
<td>Date of Entry</td>
</tr>
<tr>
<td>Mitchell Units 1 and 2</td>
<td>FGD</td>
<td>December 31, 2007</td>
</tr>
<tr>
<td>Mountaineer Unit 1</td>
<td>FGD</td>
<td>December 31, 2007</td>
</tr>
<tr>
<td>Muskingum River Units 1-4</td>
<td>Retire, Retrofit, or Re-power</td>
<td>December 31, 2015</td>
</tr>
<tr>
<td>Muskingum River Unit 5</td>
<td>Cease Burning Coal and Retire Or Cease Burning Coal and Refuel</td>
<td>December 15, 2015</td>
</tr>
</tbody>
</table>

December 31, 2015, unless the Refueling project is not completed in which case the Unit
<table>
<thead>
<tr>
<th>Unit</th>
<th>SO₂ Pollution Control</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rockport Unit 1</td>
<td>Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO₂ on a 30-Day Rolling Average Basis at the Rockport combined stack And Retrofit, Refuel, or Re-Power, but must satisfy the provisions of Paragraphs 133 and 140</td>
<td>April 16, 2015</td>
</tr>
<tr>
<td></td>
<td></td>
<td>December 31, 2020</td>
</tr>
<tr>
<td>Rockport Unit 2</td>
<td>Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO₂ on a 30-Day Rolling Average Basis at the Rockport combined stack</td>
<td>April 16, 2015</td>
</tr>
<tr>
<td></td>
<td></td>
<td>June 1, 2020</td>
</tr>
<tr>
<td>Sporn Unit 5</td>
<td>Retire, Retrofit, or Re-power</td>
<td>December 31, 2013</td>
</tr>
<tr>
<td>A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3,</td>
<td>Retire, Retrofit, or Re-power</td>
<td>December 31, 2018</td>
</tr>
<tr>
<td>Unit</td>
<td>SO₂ Pollution Control</td>
<td>Date</td>
</tr>
<tr>
<td>------</td>
<td>-----------------------</td>
<td>------</td>
</tr>
<tr>
<td>Tanners Creek Units 1-3, and/or Kammer Units 1-3</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Paragraph 89A is replaced in its entirety and now reads as follows:**

89A. **Plant-Wide Annual Tonnage Limitation and 30-Day Rolling Average Emission Rate for SO₂ at Rockport.** For each of the calendar years set forth in the table below, AEP Defendants shall limit their total annual SO₂ emissions from Rockport Units 1 and 2 to the Plant-Wide Annual Tonnage Limitation for SO₂ as follows:

<table>
<thead>
<tr>
<th>Calendar Years</th>
<th>Plant-Wide Annual Tonnage Limitation for SO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016-2017</td>
<td>28,000 tons per year</td>
</tr>
<tr>
<td>2018-2019</td>
<td>26,000 tons per year</td>
</tr>
<tr>
<td>2020</td>
<td>22,000 tons per year</td>
</tr>
<tr>
<td>2021-2028</td>
<td>10,000 tons per year</td>
</tr>
<tr>
<td>2029, and each year thereafter</td>
<td>5,000 tons per year</td>
</tr>
</tbody>
</table>

In addition to the Plant-Wide Annual Tonnage Limitation for SO₂ at Rockport, beginning on the thirtieth Day which is an Operating Day for either or both Rockport Units in calendar year 2021, SO₂ emissions from the Rockport Units shall be limited to 0.15 lb/mmBTU on a 30-Day Rolling Average Basis at the Rockport combined stack (30-Day Rolling Average Emission Rate for SO₂ at Rockport). Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B. Nothing in this Consent Decree shall be construed to prohibit the AEP Defendants from further optimizing the Enhanced DSI system, utilizing alternative sorbents, or upgrading the SO₂ removal technology at
the Rockport Units so long as the Units maintain compliance with the 30-day Rolling Average Emission Rate for SO₂ at Rockport and the 30-day Rolling Average Emission Rate for NOₓ at Rockport.

*Paragraph 127 is replaced in its entirety and now reads as follows:*

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

Pursuant to the Fifth Joint Modification Indiana Michigan Power Company ("I&M") will provide as restitution or as funds to come into compliance with the law $4 million in additional funding for the States to support projects identified in Section VIII, Subsection B during the period from 2019 through 2021. I&M shall provide the funding within seventy-five (75) days of receipt of a written request for payment and in accordance with instructions from counsel for the States.
Paragraph 128B is replaced in its entirety and now reads as follows:

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

In addition to the $2.5 million provided in 2014, pursuant to the Fifth Joint Modification I&M will provide as restitution or as funds to come into compliance with the law $3.5 million in funding for Citizen Plaintiffs to support projects that will promote energy efficiency, distributed generation, and pollution reduction measures for nonprofits, governmental entities, low income residents and/or other entities selected by Citizen Plaintiffs. I&M shall provide the $3.5 million in funding within seventy-five (75) days of the Date of Entry of the Fifth Joint Modification of the Consent Decree by the Court in accordance with instructions from counsel for Citizen Plaintiffs.

Paragraph 133 is replaced in its entirety and now reads as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that
arise based on a modification commenced before December 31, 2018, or, solely for Rockport Unit 1, before December 31, 2028, or, solely for Rockport Unit 2, before June 1, 2020, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of the original Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

With respect to Rockport Unit 1, the United States agrees that the AEP Defendants’ obligation to Retrofit, Re-Power, or Refuel Rockport Unit 1 would be satisfied if, by no later than December 31, 2028, the AEP Defendants Retrofit Rockport Unit 1 by installing and commencing continuous operation of FGD technology consistent with the definition in Paragraph 56 of the Third Joint Modification of the Consent Decree, Re-Power the Unit consistent with the definition in Paragraph 54 of the Consent Decree, or Refuel the Unit consistent with the provisions of Paragraph 53A of the Third Joint Modification of the Consent Decree. If the AEP Defendants elect to Retire Rockport Unit 1 by December 31, 2028, that would also satisfy the requirements of this Paragraph and fulfill the AEP Defendants’ obligations with regard to Rockport Unit 1 under this Consent Decree. The term “modification” as used in this paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in AEP I and AEP II.

**Paragraph 140 is replaced in its entirety and now reads as follows:**

140. With respect to the States and Citizen Plaintiffs, except as specifically set forth in this Paragraph, the States and Citizen Plaintiffs expressly do not join in giving the Defendants the
covenant provided by the United States in Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of the original Consent Decree, and reserve their rights, if any, to bring any actions against Defendants pursuant to 42 U.S.C. §7604 for any claims arising after the Date of the Lodging of the original Consent Decree. AEP, the States, and Citizen Plaintiffs also recognize that I&M informed state regulators in its most recent base rate proceedings that the most realistic date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028, and the Indiana Utility Regulatory Commission and the Michigan Public Service Commission have approved depreciation rates for I&M’s share of Rockport Unit 1 to be consistent with the retirement of Unit 1 in December 2028. Notwithstanding the existence of any other compliance options in Paragraphs 87 and 133, AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028. AEP Defendants and the States and Citizen Plaintiffs agree that Paragraph 140 prevails in any conflict between it and Paragraphs 87 and/or 133.

a. On or before March 31, 2025, AEP Defendants shall submit to PJM Interconnection, LLC, or any other regional transmission organization with jurisdiction over the Rockport Units, notification of the planned retirement of Rockport Unit 1 by no later than December 31, 2028, and a request for such regional transmission organization to evaluate and identify any reliability concerns associated with such retirement.

*Paragraph 180 is replaced in its entirety and now reads as follows:*

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state
implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO₂ at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO₂ at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO₂ at Rockport.

Paragraph 182 is replaced in its entirety and now reads as follows:

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO₂ at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO₂ at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO₂ at Rockport, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO₂ and NOₓ. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO₂ and NOₓ in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

Paragraph 188 is modified as follows to update the information required in order to provide required notices under the Consent Decree:

188.

As to the United States:

Case Management Unit
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893
eesdcopy.enrd@usdoj.gov
Phillip Brooks  
Director, Air Enforcement Division  
Office of Enforcement and Compliance Assurance  
U.S. Environmental Protection Agency  
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Washington, DC 20460  
Brooks.phillip@epa.gov

Sara Breneman  
Air Enforcement & Compliance Assurance Branch  
U.S. EPA Region 5  
77 W. Jackson Blvd.  
Mail Code AE-18J  
Chicago, IL 60604  
Breneman.sara@epa.gov

and

Carol Amend, Branch Chief  
Air, RCRA & Toxics Branch (3ED20)  
Enforcement & Compliance Assurance Division  
U.S. EPA, Region 3  
1650 Arch Street  
Philadelphia, PA 19103-2029  
Amend.carol@epa.gov

For all notices to EPA, Defendants shall register for the CDX electronic system and upload such notices at https://cdx.gov/epa-home.asp.

As to the State of Connecticut:

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Environment Department  
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Lori.dibella@ct.gov

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Air Quality Compliance Program
Maryland Department of the Environment  
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and

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As to the State of New Hampshire:

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New Hampshire Department of Environmental Services  
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and

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Environmental Enforcement  
Dept. of Law & Public Safety  
Division of Law  
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Lisa.morelli@dol.lps.state.nj.us

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Assistant Attorney General
Office of the Attorney General
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As to the Citizen Plaintiffs:

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As to Gavin Buyer:

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Nicholas.tipple@lightstone.com
Karl A. Karg  
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and

Alexandra Farmer  
Kirkland & Ellis LLP
1301 Pennsylvania Avenue, N.W.
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alexandra.farmer@kirkland.com

Add a new Paragraph 205A that reads as follows:

205A. 26 U.S.C. Section 162(f)(2)(A)(ii) Identification. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), with respect to obligations incurred under this Fifth Joint Modification, performance of Section II (Applicability), Paragraph 3; Section IV (NOx Emission Reductions and Controls), Paragraphs 67, 68, 68A, and 68B; Section V (SO2 Emission Reductions and Controls), Paragraphs 86, 87, and 89A; Section VII (Prohibition on Netting Credits or Offsets from Required Controls), Paragraph 117; Section XI (Periodic Reporting), Paragraphs 143 – 147; Section XII (Review and Approval of Submittals), Paragraphs 148 and 149 (except with respect to dispute resolution); Section XVI (Permits), Paragraphs 175, 177, 179, and 180 – 183; Section XVII (Information Collection and Retention), Paragraphs 184 and 185; Section XXIII (General Provisions), Paragraph 207; and Appendix B; is restitution or required to come into compliance with law.

Modify Appendix B (Reporting Requirements) as follows:

Section I Paragraph O is replaced in its entirety and now reads as follows:

O. Plant-Wide Annual Tonnage Limitation and Emission Rate for SO2 at Rockport.
Beginning March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO₂ emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO₂ at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 - 2020, Defendants shall report the daily sorbent deliveries to the Rockport Plant by weight. Beginning in calendar year 2021, the annual reports shall report the 30-day rolling average SO₂ Emissions Rate at the Rockport stack as required under Section I, Paragraph J of Appendix B, and reporting of daily sorbent deliveries will no longer be required.

Section I Paragraph S. is replaced in its entirety and now reads as follows:

S. Notification of Retirement of Rockport Unit 1.

AEP Defendants shall provide to the Plaintiffs a copy of the notification submitted to PJM Interconnection, LLC, or any other regional transmission organization pursuant to Paragraph 140.a, and a copy of any response received from PJM Interconnection, LLC, or any other the regional transmission organization.

Delete Paragraphs T and U from Section I of Appendix B.

Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS ___ DAY OF ___ , 2019.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE
SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

Civil Action No. 99-CV-1182 and consolidated cases

FOR THE UNITED STATES

Myle E. Flint, II
Senior Counsel
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
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FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

Civil Action No. 99-CV-1182 and consolidated cases

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United States Environmental Protection Agency

Phillip A. Brooks
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in

Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF CONNECTICUT

WILLIAM TONG
ATTORNEY GENERAL

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   Assistant Attorney General
   Office of the Attorney General
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   Hartford, CT 06141-0120
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Attorney General

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Civil Action No. 99-CV-1182 and consolidated cases

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in 

Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF RHODE ISLAND

PETER F. NERONHA
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[Signature]

Gregory S. Schintz
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Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF VERMONT

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FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.

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Civil Action No. 99-CV-1182 and consolidated cases

FOR SIERRA CLUB

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Sierra Club
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FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

Civil Action No. 99-CV-1182 and consolidated cases

FOR OHIO CITIZEN ACTION, CITIZENS ACTION
COALITION OF INDIANA, HOOSIER
ENVIRONMENTAL COUNCIL, OHIO VALLEY
ENVIRONMENTAL COALITION, WEST VIRGINIA
ENVIRONMENTAL COUNCIL, CLEAN AIR
COUNCIL, IZAAK WALTON LEAGUE OF
AMERICA, ENVIRONMENT AMERICA,
NATIONAL WILDLIFE FEDERATION, INDIANA
WILDLIFE FEDERATION, AND LEAGUE OF OHIO
SPORTSMEN

Margrethe Kearney
Environmental Law and Policy Center
35 East Wacker Drive, Suite 1600
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FIFTH JOINT MODIFICATION OF THE CONSENT DEGREE

in

Civil Action No. 99-CV-1182 and consolidated cases

FOR THE AEP COMPANIES

David M. Feinberg
American Electric Power
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Columbus, OH 43215
Attachment H

Part 70 Operating Permit No: 147-40656-00020

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

What This Subpart Covers

§60.4200 Am I subject to this subpart?

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

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

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

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

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

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

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

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

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

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

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.
(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

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

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

Emission Standards for Manufacturers

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

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

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

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

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

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

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

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

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

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and
(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

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

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

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

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

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

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

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

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


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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Remote areas of Alaska; and


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

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]
§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

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

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.
(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

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

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

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

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

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

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

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

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

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

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

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

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

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

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

   (ii) 44 \cdot n^{-0.23} g/KW-hr (33 \cdot n^{-0.23} g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where \( n \) is maximum engine speed; and
(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

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

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

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

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

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

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

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

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

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

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

(c) [Reserved]

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

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


Other Requirements for Owners and Operators

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

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.
(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2008 model year non-emergency engines.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.
(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

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

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

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

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

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

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

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

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

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all of the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR 89.112 when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016]
§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) Identification of the specific parameters you propose to monitor continuously;
(ii) A discussion of the relationship between these parameters and NO\textsubscript{x} and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO\textsubscript{x} and PM emissions;

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

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

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

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

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

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

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

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

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

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

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

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.
(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

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

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of
stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219,
July 7, 2016]

Testing Requirements for Owners and Operators

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

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

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

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

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in
40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the
same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable,
determined from the following equation:

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

Where:

\[
\text{STD} = \text{The standard specified for that pollutant in } 40 \text{ CFR 89.112 or 40 CFR 94.8, as applicable.}
\]

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

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

Where:

\[
\text{STD} = \text{The standard specified for that pollutant in } 60.4204(a), 60.4205(a), \text{ or } 60.4205(c).
\]

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in
§60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.
(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

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

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

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

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

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

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

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

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

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

Where:

\( C_i \) = concentration of NOx or PM at the control device inlet,

\( C_o \) = concentration of NOx or PM at the control device outlet, and

\( R \) = percent reduction of NOx or PM emissions.

(2) You must normalize the NOx or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO2) using the procedures described in paragraph (d)(3) of this section.

\[
C_{adj} = C_d \frac{5.9}{20.9 - \%O_2} \quad \text{(Eq. 3)}
\]

Where:

\( C_{adj} \) = Calculated NOx or PM concentration adjusted to 15 percent O2.

\( C_d \) = Measured concentration of NOx or PM, uncorrected.

5.9 = 20.9 percent O2−15 percent O2, the defined O2 correction value, percent.
%O₂ = Measured O₂ concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O₂ and CO₂ concentration is measured in lieu of O₂ concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

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

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

Where:

\(F_o\) = Fuel factor based on the ratio of O₂ volume to the ultimate CO₂ volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O₂, percent/100.

\(F_d\) = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

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

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

\[
X_{CO₂} = \frac{5.9}{F_o} \quad \text{(Eq. 5)}
\]

Where:

\(X_{CO₂}\) = CO₂ correction factor, percent.

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

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

\[
C_{adj} = C_d \times \frac{X_{CO₂}}{%CO₂} \quad \text{(Eq. 6)}
\]

Where:

\(C_{adj}\) = Calculated NOₓ or PM concentration adjusted to 15 percent O₂.

\(C_d\) = Measured concentration of NOₓ or PM, uncorrected.

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

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

\[ ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \]  

(Eq. 7)

ER = Emission rate in grams per KW-hour.

\[ C_d = \text{Measured NOX concentration in ppm.} \]

\[ 1.912 \times 10^{-3} = \text{Conversion constant for ppm NOX to grams per standard cubic meter at 25 degrees Celsius.} \]

\[ Q = \text{Stack gas volumetric flow rate, in standard cubic meter per hour.} \]

\[ T = \text{Time of test run, in hours.} \]

\[ \text{KW-hour} = \text{Brake work of the engine, in KW-hour.} \]

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

\[ ER = \frac{C_{\text{adj}} \times Q \times T}{\text{KW-hour}} \]  

(Eq. 8)

Where:

ER = Emission rate in grams per KW-hour.

\[ C_{\text{adj}} = \text{Calculated PM concentration in grams per standard cubic meter.} \]

\[ Q = \text{Stack gas volumetric flow rate, in standard cubic meter per hour.} \]

\[ T = \text{Time of test run, in hours.} \]

\[ \text{KW-hour} = \text{Energy output of the engine, in KW.} \]

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

**Notification, Reports, and Records for Owners and Operators**

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

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

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

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

(ii) The address of the affected source;
(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

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

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

(ii) Maintenance conducted on the engine.

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

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

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

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

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

(1) The report must contain the following information:

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

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

(iii) Engine site rating and model year.

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

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

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

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).


Special Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]
§60.4216  What requirements must I meet for engines used in Alaska?

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

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in §§60.4201(f) and 60.4202(g).

(c) Manufacturers, owners and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§60.4202 and 60.4205, and not those for non-emergency engines in §§60.4201 and 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §§60.4201 and 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

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

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

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

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016]

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

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

[76 FR 37972, June 28, 2011]

General Provisions

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

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

§60.4219 What definitions apply to this subpart?

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

*Alaska Railbelt Grid* means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

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

*Combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

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

*Date of manufacture* means one of the following things:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*Remote areas of Alaska* means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.
(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

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

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

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

*Subpart* means 40 CFR part 60, subpart III.


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

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

<table>
<thead>
<tr>
<th>Maximum engine power</th>
<th>Emission standards for stationary pre-2007 model year engines with a displacement of &lt;10 liters per cylinder and 2007-2010 model year engines &gt;2,237 KW (3,000 HP) and with a displacement of &lt;10 liters per cylinder in g/KW-hr (g/HP-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NMHC + NO&lt;sub&gt;x&lt;/sub&gt;</td>
</tr>
<tr>
<td>KW&lt;8 (HP&lt;11)</td>
<td>10.5 (7.8)</td>
</tr>
<tr>
<td>8≤KW&lt;19 (11≤HP&lt;25)</td>
<td>9.5 (7.1)</td>
</tr>
<tr>
<td>19≤KW&lt;37 (25≤HP&lt;50)</td>
<td>9.5 (7.1)</td>
</tr>
<tr>
<td>37≤KW&lt;56 (50≤HP&lt;75)</td>
<td>9.2 (6.9)</td>
</tr>
<tr>
<td>56≤KW&lt;75 (75≤HP&lt;100)</td>
<td>9.2 (6.9)</td>
</tr>
<tr>
<td>75≤KW&lt;130 (100≤HP&lt;175)</td>
<td>9.2 (6.9)</td>
</tr>
<tr>
<td>130≤KW&lt;225 (175≤HP&lt;300)</td>
<td>1.3 (1.0)</td>
</tr>
<tr>
<td>225≤KW&lt;450 (300≤HP&lt;600)</td>
<td>1.3 (1.0)</td>
</tr>
</tbody>
</table>
Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

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

<table>
<thead>
<tr>
<th>Engine power</th>
<th>Model year(s)</th>
<th>NOx + NMHC</th>
<th>CO</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;8 (HP&lt;11)</td>
<td>2008 +</td>
<td>7.5 (5.6)</td>
<td>8.0 (6.0)</td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>8≤KW&lt;19 (11≤HP&lt;25)</td>
<td>2008 +</td>
<td>7.5 (5.6)</td>
<td>6.6 (4.9)</td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>19≤KW&lt;37 (25≤HP&lt;50)</td>
<td>2008 +</td>
<td>7.5 (5.6)</td>
<td>5.5 (4.1)</td>
<td>0.30 (0.22)</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Engine power</th>
<th>Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;75 (HP&lt;100)</td>
<td>2011</td>
</tr>
<tr>
<td>75≤KW&lt;130 (100≤HP&lt;175)</td>
<td>2010</td>
</tr>
<tr>
<td>130≤KW&lt;560 (175≤HP&lt;750)</td>
<td>2009</td>
</tr>
<tr>
<td>KW&gt;560 (HP&gt;750)</td>
<td>2008</td>
</tr>
</tbody>
</table>

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

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]
Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

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

<table>
<thead>
<tr>
<th>Maximum engine power</th>
<th>Model year(s)</th>
<th>NMHC + NOX</th>
<th>CO</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;8 (HP&lt;11)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>8.0 (6.0)</td>
<td>1.0 (0.75)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td></td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>8≤KW&lt;19 (11≤HP&lt;25)</td>
<td>2010 and earlier</td>
<td>9.5 (7.1)</td>
<td>6.6 (4.9)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td></td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>19≤KW&lt;37 (25≤HP&lt;50)</td>
<td>2010 and earlier</td>
<td>9.5 (7.1)</td>
<td>5.5 (4.1)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td></td>
<td>0.30 (0.22)</td>
</tr>
<tr>
<td>37≤KW&lt;56 (50≤HP&lt;75)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>5.0 (3.7)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +¹</td>
<td>4.7 (3.5)</td>
<td></td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>56≤KW&lt;75 (75≤HP&lt;100)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>5.0 (3.7)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +¹</td>
<td>4.7 (3.5)</td>
<td></td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>75≤KW&lt;130 (100≤HP&lt;175)</td>
<td>2009 and earlier</td>
<td>10.5 (7.8)</td>
<td>5.0 (3.7)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2010 +²</td>
<td>4.0 (3.0)</td>
<td></td>
<td>0.30 (0.22)</td>
</tr>
<tr>
<td>130≤KW&lt;225 (175≤HP&lt;300)</td>
<td>2008 and earlier</td>
<td>10.5 (7.8)</td>
<td>3.5 (2.6)</td>
<td>0.54 (0.40)</td>
</tr>
<tr>
<td></td>
<td>2009 +³</td>
<td>4.0 (3.0)</td>
<td></td>
<td>0.20 (0.15)</td>
</tr>
<tr>
<td>225≤KW&lt;450 (300≤HP&lt;600)</td>
<td>2008 and earlier</td>
<td>10.5 (7.8)</td>
<td>3.5 (2.6)</td>
<td>0.54 (0.40)</td>
</tr>
<tr>
<td></td>
<td>2009 +³</td>
<td>4.0 (3.0)</td>
<td></td>
<td>0.20 (0.15)</td>
</tr>
<tr>
<td>450≤KW≤560 (600≤HP≤750)</td>
<td>2008 and earlier</td>
<td>10.5 (7.8)</td>
<td>3.5 (2.6)</td>
<td>0.54 (0.40)</td>
</tr>
<tr>
<td></td>
<td>2009 +</td>
<td>4.0 (3.0)</td>
<td></td>
<td>0.20 (0.15)</td>
</tr>
<tr>
<td>KW&gt;560 (HP&gt;750)</td>
<td>2007 and earlier</td>
<td>10.5 (7.8)</td>
<td>3.5 (2.6)</td>
<td>0.54 (0.40)</td>
</tr>
<tr>
<td></td>
<td>2008 +</td>
<td>6.4 (4.8)</td>
<td></td>
<td>0.20 (0.15)</td>
</tr>
</tbody>
</table>

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

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

³In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.
Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

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

<table>
<thead>
<tr>
<th>Engine power</th>
<th>Starting model year</th>
</tr>
</thead>
<tbody>
<tr>
<td>19 ≤ kW &lt; 56 (25 ≤ HP &lt; 75)</td>
<td>2013</td>
</tr>
<tr>
<td>56 ≤ kW &lt; 130 (75 ≤ HP &lt; 175)</td>
<td>2012</td>
</tr>
<tr>
<td>kW ≥ 130 (HP ≥ 175)</td>
<td>2011</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Mode No.</th>
<th>Engine speed</th>
<th>Torque (percent)</th>
<th>Weighting factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Rated</td>
<td>100</td>
<td>0.30</td>
</tr>
<tr>
<td>2</td>
<td>Rated</td>
<td>75</td>
<td>0.50</td>
</tr>
<tr>
<td>3</td>
<td>Rated</td>
<td>50</td>
<td>0.20</td>
</tr>
</tbody>
</table>

1Engine speed: ±2 percent of point.

2Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.
Table 7 to Subpart III of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

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

<table>
<thead>
<tr>
<th>Each</th>
<th>Complying with the requirement to</th>
<th>You must</th>
<th>Using</th>
<th>According to the following requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder</td>
<td>a. Reduce NOX emissions by 90 percent or more;</td>
<td>i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;</td>
<td>(a) For NOX, O2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (&quot;3-point long line&quot;). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(b) Measurements to determine O2 concentration must be made at the same time as the measurements for NOX concentration.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>ii. Measure O2 at the inlet and outlet of the control device;</td>
<td>(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>iii. If necessary, measure moisture content at the inlet and outlet of the control device; and</td>
<td>(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(c) Measurements to determine moisture content must be made at the same time as the measurements for NOX concentration.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>iv. Measure NOX at the inlet and outlet of the control device.</td>
<td>(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(d) NOX concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
<td></td>
</tr>
<tr>
<td>Each</td>
<td>Complying with the requirement to</td>
<td>You must</td>
<td>Using</td>
<td>According to the following requirements</td>
</tr>
<tr>
<td>------</td>
<td>----------------------------------</td>
<td>----------</td>
<td>-------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td></td>
<td>b. Limit the concentration of NO\textsubscript{x} in the stationary CI internal combustion engine exhaust.</td>
<td>i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;</td>
<td>(a) For NO\textsubscript{x}, O\textsubscript{2}, and moisture measurement, ducts \leq 6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and \leq 12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (&quot;3-point long line&quot;). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Determine the O\textsubscript{2} concentration of the stationary internal combustion engine exhaust at the sampling port location;</td>
<td>(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td>(b) Measurements to determine O\textsubscript{2} concentration must be made at the same time as the measurement for NO\textsubscript{x} concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and</td>
<td>(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(c) Measurements to determine moisture content must be made at the same time as the measurement for NO\textsubscript{x} concentration.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iv. Measure NO\textsubscript{x} at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.</td>
<td>(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(d) NO\textsubscript{x} concentration must be at 15 percent O\textsubscript{2}, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td></td>
<td>c. Reduce PM emissions by 60 percent or more</td>
<td>i. Select the sampling port location and the number of traverse points;</td>
<td>(1) Method 1 or 1A of 40 CFR part 60, appendix A-1</td>
<td>(a) Sampling sites must be located at the inlet and outlet of the control device.</td>
</tr>
</tbody>
</table>
### Each Complying with the Requirement to

<table>
<thead>
<tr>
<th>Step</th>
<th>Complying with the requirement to</th>
<th>Using</th>
<th>According to the following requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>ii.</td>
<td>Measure $O_2$ at the inlet and outlet of the control device;</td>
<td>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td>(b) Measurements to determine $O_2$ concentration must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td>iii.</td>
<td>If necessary, measure moisture content at the inlet and outlet of the control device; and</td>
<td>(3) Method 4 of 40 CFR part 60, appendix A-3</td>
<td>(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td>iv.</td>
<td>Measure PM at the inlet and outlet of the control device.</td>
<td>(4) Method 5 of 40 CFR part 60, appendix A-3</td>
<td>(d) PM concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
</tbody>
</table>

### d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust

<table>
<thead>
<tr>
<th>Step</th>
<th>Subject of citation</th>
<th>Applies to subpart</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>i.</td>
<td>Select the sampling port location and the number of traverse points;</td>
<td>(1) Method 1 or 1A of 40 CFR part 60, appendix A-1</td>
<td>(a) If using a control device, the sampling site must be located at the outlet of the control device.</td>
</tr>
<tr>
<td>ii.</td>
<td>Determine the $O_2$ concentration of the stationary internal combustion engine exhaust at the sampling port location;</td>
<td>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td>(b) Measurements to determine $O_2$ concentration must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td>iii.</td>
<td>If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and</td>
<td>(3) Method 4 of 40 CFR part 60, appendix A-3</td>
<td>(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td>iv.</td>
<td>Measure PM at the exhaust of the stationary internal combustion engine.</td>
<td>(4) Method 5 of 40 CFR part 60, appendix A-3</td>
<td>(d) PM concentration must be at 15 percent $O_2$, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
</tbody>
</table>

[79 FR 11251, Feb. 27, 2014]

**Table 8 to Subpart III of Part 60—Applicability of General Provisions to Subpart III**

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

<table>
<thead>
<tr>
<th>General Provisions citation</th>
<th>Subject of citation</th>
<th>Applies to subpart</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>§60.1</td>
<td>General applicability of the General Provisions</td>
<td>Yes</td>
<td>Additional terms defined in §60.4219.</td>
</tr>
<tr>
<td>§60.2</td>
<td>Definitions</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>General Provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>---------------------</td>
<td>--------------------</td>
<td>-------------</td>
</tr>
<tr>
<td>§60.3</td>
<td>Units and abbreviations</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.4</td>
<td>Address</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.5</td>
<td>Determination of construction or modification</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.6</td>
<td>Review of plans</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.7</td>
<td>Notification and Recordkeeping</td>
<td>Yes</td>
<td>Except that §60.7 only applies as specified in §60.4214(a).</td>
</tr>
<tr>
<td>§60.8</td>
<td>Performance tests</td>
<td>Yes</td>
<td>Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.</td>
</tr>
<tr>
<td>§60.9</td>
<td>Availability of information</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.10</td>
<td>State Authority</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.11</td>
<td>Compliance with standards and maintenance requirements</td>
<td>No</td>
<td>Requirements are specified in subpart III.</td>
</tr>
<tr>
<td>§60.12</td>
<td>Circumvention</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.13</td>
<td>Monitoring requirements</td>
<td>Yes</td>
<td>Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.</td>
</tr>
<tr>
<td>§60.14</td>
<td>Modification</td>
<td>Yes</td>
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Technical Support Document - Appendix A - Emission Calculations

Summary

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit No.:** 147-40656-00020  
**Reviewer:** Mena Mekhail

<table>
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<tr>
<th>PTE</th>
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<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
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Total 319,382.42 79,746.82 26,593.37 73,339.49 49,224.70 406.58 3,480.25 32,207,567.51 7,805.78 8,857.88

* Ash Handling  
** ACI, DSI, and Ash Hauling
Technical Support Document - Appendix A - Emission Calculations

Summary

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit No.:** 147-40656-00020  
**Reviewer:** Mena Mekhail

### Limited Emissions

<table>
<thead>
<tr>
<th>Source Type</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>GHG</th>
<th>Single HAP</th>
<th>Total HAPs</th>
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<tr>
<td>MB 1 and MB2*</td>
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<td>8,857.51</td>
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<td>86.78</td>
<td>58.48</td>
<td>2,678.87</td>
<td>905.53</td>
<td>7.55</td>
<td>188.65</td>
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<tr>
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<td>36.73</td>
<td>5.51</td>
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<td>32,282,209.01</td>
<td>7,805.78</td>
<td>8,857.88</td>
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* PM, PM10, PM2.5 are Source mod 32899 limits  
** Ash Hauling Unpaved Road Limit  
*** ACI, DSI, and Ash Hauling
Appendix A: Emission Calculations
Coal Combustion: MB1 and MB2

Address, City, IN, Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40856-00020
Reviewer: Mona Mehlkai

PM, tons/yr @ 2002 coal & 0.0442 lb/MMBtu = 0.0442 lb/MMBtu x coal throughput (tons/yr) x heat content (Btu/lb) x MMBtu/10E6 Btu x 2000 lb/ton


Methodology
Emission Factors are from AP-42, Chapter 1.1. Tables 1.1-12, 1.1-13, 1.1-14, 1.1-15, 1.1-18, and 1.1-19.

HAPs emission factors are from AP-42, Chapter 1.1: Tables 1.1-12, 1.1-13, 1.1-14, 1.1-15, 1.1-18, and 1.1-19.

This table includes all HAPs listed in AP-42 with an emission factor of 1E-04 pound per ton or more plus total polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF), total polynuclear aromatic hydrocarbons (PAH), mercury, and beryllium, using electrostatic precipitators (ESP) for control.

**Methodology is the same as page 1.**

**HAPs emissions factors are from AP-42, Chapter 1.1. Tables 1.1-12, 1.1-13, 1.1-14, 1.1-15, 1.1-18, and 1.1-19.**

This table includes all HAPs listed in AP-42 with an emission factor of 1E-04 pound per ton or more plus total polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF), total polynuclear aromatic hydrocarbons (PAH), mercury, and beryllium, using electrostatic precipitators (ESP) for control. PAH emission factor is the sum of the individual PAH factors in AP-42, Table 1.1-13.


**Methodology is the same as page 1.**

*Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton.
Emissions (lb/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2,000 lb/ton x Emission Factor (lb/ton).*

Limited Emission
MB1 and MB2
PM PSD Limit 0.1 lb/MMBtu Emissions 10,839.62 tpy
NOx PSD Limit 0.7 lb/MMBtu Emissions 7587.48 tpy
NOx NSPS Limit 0.7 lb/MMBtu Emissions 7587.48 tpy

Controlled NOx 28,896.99 tpy 40% control eff
Controlled PM 935.25 tpy 99.7% Control eff
Appendix A: Emissions Calculations
2 Auxiliary Boilers
#1 and #2 Fuel Oil

Address, City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
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<td>58.48</td>
<td>2678.87</td>
<td>905.53</td>
<td>7.55</td>
<td>188.65</td>
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</table>

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-02-005-01/02/03) Supplement E 9/98 *PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

See Page 5 for HAPs calculations.

Appendix A: Emissions Calculations

2 Auxiliary Boilers
#1 and #2 Fuel Oil
HAPs Emissions

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<td>Permit Number:</td>
<td>147-29841-00020</td>
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<td>Reviewer:</td>
<td>Mena Mekhail</td>
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<td>Beryllium</td>
</tr>
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<td>Cadmium</td>
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<td>Chromium</td>
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<td>Lead</td>
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<td>4.75E-02</td>
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<td>Mercury</td>
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<td>Selenium</td>
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<td>1.58E-02</td>
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<tr>
<td>7.92E-02</td>
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Total = 0.26
Methodology

No data was available in AP-42 for organic HAPs.
Potential Emissions (tons/year) = Throughput (mmBtu/hr) x Emission Factor (lb/mmBtu) x 8,760 hrs/yr / 2,000 lb/ton

See Page 6 for Greenhouse Gas calculations.

Appendix A: Emissions Calculations
2 Auxilary Boilers
#1 and #2 Fuel Oil
Greenhouse Gas Emissions

| Address, City IN Zip: | 2791 North US Highway 231, Rockport, Indiana 47635 |
| Permit Number: | 147-40656-00020 |
| Reviewer: | Mena Mekhail |

<table>
<thead>
<tr>
<th>Emission Factor in lb/kgal</th>
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<th>N2O</th>
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<td>CO2e Total in tons/yr</td>
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</tbody>
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Methodology

The CO2 Emission Factor for #1 Fuel Oil is 21500. The CO2 Emission Factor for #2 Fuel Oil is 22300.
Emission Factors are from AP 42, Tables 1.3-3, 1.3-8, and 1.3-12 (SCC 1-03-005-01/02/03) Supplement E 9/99 (see erata file)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (kgals/yr) x Emission Factor (lb/kgal) / 2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).
**Limited Emissions**

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<th>Emissions tpy</th>
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<td>SO2 NSPS Limit</td>
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<td>NOX NSPS Limit</td>
<td>0.3 lb/MMBTu</td>
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Appendix A: Emission Calculations
emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address City IN Zip:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit Number:** 147-40656-00020  
**Reviewer:** Mena Mekhail

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<table>
<thead>
<tr>
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<td><strong>Heat Input Capacity (MMBtu/hr)</strong></td>
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</tbody>
</table>

*No information was given regarding which method was used to determine the PM emission factor or whether condensable PM is included. The PM10 emission factor is filterable and condensable PM10 combined. The PM2.5 emissions were assumed to be equal to PM10.

**NOx emissions: uncontrolled = 3.2 lb/MMBtu, controlled with ignition timing retard = 1.9 lb/MMBtu

Hazardous Air Pollutants (HAPs)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Benzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>Formaldehyde</th>
<th>Acetaldehyde</th>
<th>Acrolein</th>
<th>Total PAH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>7.76E-04</td>
<td>2.81E-04</td>
<td>1.93E-04</td>
<td>7.89E-05</td>
<td>2.52E-05</td>
<td>7.88E-06</td>
<td>2.12E-04</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>4.89E-03</td>
<td>1.77E-03</td>
<td>1.22E-03</td>
<td>4.97E-04</td>
<td>1.59E-04</td>
<td>4.96E-05</td>
<td>1.34E-03</td>
</tr>
</tbody>
</table>

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

**Potential Emission of Total HAPs (tons/yr)** | 0.01 |
Appendix A: Emission Calculations
Emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Address City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

Green House Gas Emissions (GHG)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>CO2 Emission Factor in lb/MMBtu</th>
<th>CH4 Emission Factor in lb/MMBtu</th>
<th>N2O Emission Factor in lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>1.65E+02</td>
<td>8.10E-03</td>
<td>1.32E-03</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>1.04E+03</td>
<td>5.10E-02</td>
<td>8.33E-03</td>
</tr>
</tbody>
</table>

Summed Potential Emissions in tons/yr: 1039.56
CO2e Total in tons/yr: 1043.16

Potential Throughput (MMBtu/yr) = [Heat Input Capacity (MMBtu/hr)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).
Appendix A: Emission Calculations

Emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

| Address City IN Zip: | 2791 North US Highway 231, Rockport, Indiana 47635 |
| Permit Number: | 147-40656-00020 |
| Reviewer: | Mena Mekhail |

- Heat Input Capacity (MMBtu/hr): 25.2
- Maximum Hours Operated per Year: 500
- Potential Throughput (MMBtu/yr): 12,600
- Content (S) of Fuel (% by weight): 0.500

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>0.10</td>
<td>0.0573</td>
<td>0.505</td>
<td>3.2</td>
<td>0.09</td>
<td>0.85</td>
<td></td>
</tr>
<tr>
<td>Potential Emission in t/yr</td>
<td>0.63</td>
<td>0.36</td>
<td>3.18</td>
<td>20.16</td>
<td>0.57</td>
<td>5.36</td>
<td></td>
</tr>
</tbody>
</table>

*No information was given regarding which method was used to determine the PM emission factor or whether condensable PM is included. The PM10 emission factor is filterable and condensable PM10 combined. The PM2.5 emissions were assumed to be **see below**

**NOx emissions: uncontrolled = 3.2 lb/MMBtu, controlled with ignition timing retard = 1.9 lb/MMBtu

Hazardous Air Pollutants (HAPs)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Benzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>formaldehyde</th>
<th>acetaldehyde</th>
<th>Acrolein</th>
<th>Total PAH HAPs***</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>7.76E-04</td>
<td>2.81E-04</td>
<td>1.93E-04</td>
<td>7.89E-05</td>
<td>2.52E-05</td>
<td>7.88E-06</td>
<td>2.12E-04</td>
</tr>
<tr>
<td>Potential Emission in t/yr</td>
<td>4.89E-03</td>
<td>1.77E-03</td>
<td>1.22E-03</td>
<td>4.97E-04</td>
<td>1.59E-04</td>
<td>4.96E-05</td>
<td>1.34E-03</td>
</tr>
</tbody>
</table>

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

Potential Emission of Total HAPs (tons/yr): 0.01
Appendix A: Emission Calculations
Emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Address City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

Green House Gas Emissions (GHG)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>CO2</th>
<th>CH4</th>
<th>N2O</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu/hr</td>
<td>1.65E+02</td>
<td>8.10E-03</td>
<td>1.32E-03</td>
</tr>
<tr>
<td>Potential Emission in t</td>
<td>1.04E+03</td>
<td>5.10E-02</td>
<td>8.33E-03</td>
</tr>
</tbody>
</table>

| Summed Potential Emissions in tons/yr | 1039.56 |
| CO2e Total in tons/yr | 1043.16 |

Potential Throughput (MMBtu/yr) = [Heat Input Capacity (MMBtu/hr)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).
### Appendix A: Emission Calculations

**Emergency Generator - Diesel Fuel**

**Output Rating (>600 HP)**

**Maximum Input Rate (>4.2 MMBtu/hr)**

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address City IN Zip:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit Number:** 147-40656-00020  
**Reviewer:** Mena Mekhail

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Input Capacity (MMBtu/hr)</td>
<td>25.2</td>
</tr>
<tr>
<td>Maximum Hours Operated per Year</td>
<td>500</td>
</tr>
<tr>
<td>Potential Throughput (MMBtu/yr)</td>
<td>12,600</td>
</tr>
<tr>
<td>Sulfur Content (S) of Fuel (% by weight)</td>
<td>0.500</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>Direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>0.10</td>
<td>0.0573</td>
<td>0.0573</td>
<td>0.505</td>
<td>3.2</td>
<td>0.09</td>
<td>0.85</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>0.63</td>
<td>0.36</td>
<td>0.36</td>
<td>3.18</td>
<td>20.16</td>
<td>0.57</td>
<td>5.36</td>
</tr>
</tbody>
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*No information was given regarding which method was used to determine the PM emission factor or whether condensible PM is included. The PM10 emission factor is filterable and condensible PM10 combined. The PM2.5 emissions were assumed to be equal to PM10.

**NOx emissions:** uncontrolled = 3.2 lb/MMBtu, controlled with ignition timing retard = 1.9 lb/MMBtu

### Hazardous Air Pollutants (HAPs)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Benzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>Formaldehyde</th>
<th>Acetaldehyde</th>
<th>Acrolein</th>
<th>Total PAH HAPs***</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>7.76E-04</td>
<td>2.81E-04</td>
<td>1.93E-04</td>
<td>7.89E-05</td>
<td>2.52E-05</td>
<td>7.88E-06</td>
<td>2.12E-04</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>4.89E-03</td>
<td>1.77E-03</td>
<td>1.22E-03</td>
<td>4.97E-04</td>
<td>1.59E-04</td>
<td>4.96E-05</td>
<td>1.34E-03</td>
</tr>
</tbody>
</table>

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

Potential Emission of Total HAPs (tons/yr) | 0.01
Appendix A: Emission Calculations
Emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Address City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

Green House Gas Emissions (GHG)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>CO2</th>
<th>CH4</th>
<th>N2O</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>1.65E+02</td>
<td>8.10E-03</td>
<td>1.32E-03</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>1.04E+03</td>
<td>5.10E-02</td>
<td>8.33E-03</td>
</tr>
</tbody>
</table>

Summed Potential Emissions in tons/yr 1039.56
CO2 Total in tons/yr 1043.16

Potential Throughput (MMBtu/yr) = [Heat Input Capacity (MMBtu/hr)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).
Appendix A: Emission Calculations

Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Source Address: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-4056-00020
Reviewer: Mena Mekhail

Emissions calculated based on output rating (hp)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr</th>
<th>Potential Emission in tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>PM10*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>direct PM2.5*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>SO2</td>
<td>0.00205</td>
<td>2.74</td>
</tr>
<tr>
<td>NOx</td>
<td>0.0310</td>
<td>41.41</td>
</tr>
<tr>
<td>VOC</td>
<td>0.0025</td>
<td>3.36</td>
</tr>
<tr>
<td>CO</td>
<td>0.00668</td>
<td>8.92</td>
</tr>
</tbody>
</table>

**PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.**

Hazardous Air Pollutants (HAPs)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr****</th>
<th>Potential Emission in tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benzene</td>
<td>6.53E-06</td>
<td>8.72E-03</td>
</tr>
<tr>
<td>Toluene</td>
<td>2.86E-06</td>
<td>3.82E-03</td>
</tr>
<tr>
<td>Xylene</td>
<td>2.00E-06</td>
<td>2.67E-03</td>
</tr>
<tr>
<td>1,3-Butadiene</td>
<td>2.74E-07</td>
<td>3.66E-04</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>8.26E-06</td>
<td>1.10E-02</td>
</tr>
<tr>
<td>Acetaldehyde</td>
<td>5.37E-06</td>
<td>7.17E-03</td>
</tr>
<tr>
<td>Acrolein</td>
<td>6.48E-07</td>
<td>8.65E-04</td>
</tr>
<tr>
<td>Total PAH HAPs***</td>
<td>1.18E-06</td>
<td>1.57E-03</td>
</tr>
</tbody>
</table>

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)***

Potential Emission of Total HAPs (tons/yr) 3.62E-02

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr</th>
<th>Potential Emission in tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>1.15E+00</td>
<td>9.26E-06</td>
</tr>
<tr>
<td>CH4</td>
<td>4.63E-05</td>
<td>6.18E-02</td>
</tr>
<tr>
<td>N2O</td>
<td>9.28E-06</td>
<td>1.24E-02</td>
</tr>
</tbody>
</table>

Summed Potential Emissions in tons/yr 1.54E+03

CO2e Total in tons/yr 1.54E+03

Methodology

CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
### Reciprocating Internal Combustion Engines - Diesel Fuel

#### Output Rating (<=600 HP)

**Maximum Input Rate (<=4.2 MMBtu/hr)**

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Source Address:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit Number:** 147-4056-00020  
**Reviewer:** Mena Mekhail

Emissions calculated based on output rating (hp)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr</th>
<th>Potential Emission in tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>PM10*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>direct PM2.5*</td>
<td>0.0022</td>
<td>2.94</td>
</tr>
<tr>
<td>SO2</td>
<td>0.00205</td>
<td>8.24</td>
</tr>
<tr>
<td>NOx</td>
<td>0.0310</td>
<td>41.44</td>
</tr>
<tr>
<td>VOC</td>
<td>0.0025</td>
<td>2.74</td>
</tr>
<tr>
<td>CO</td>
<td>0.00668</td>
<td>3.36</td>
</tr>
</tbody>
</table>

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

<table>
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<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr****</th>
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</thead>
<tbody>
<tr>
<td>Benzene</td>
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</tr>
<tr>
<td>Xylene</td>
<td>2.00E-06</td>
<td>3.02E-03</td>
</tr>
<tr>
<td>1,3-Butadiene</td>
<td>2.74E-07</td>
<td>3.77E-03</td>
</tr>
<tr>
<td>Formaldehyde</td>
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</tr>
<tr>
<td>Acetaldehyde</td>
<td>5.37E-06</td>
<td>7.17E-03</td>
</tr>
<tr>
<td>Acrolein</td>
<td>6.48E-07</td>
<td>8.65E-04</td>
</tr>
<tr>
<td>Total PAH HAPs***</td>
<td>1.18E-06</td>
<td>1.57E-03</td>
</tr>
</tbody>
</table>

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

Hazardous Air Pollutants (HAPs)

**Potential Emission of Total HAPs (tons/yr) 3.62E-02**

**Methodology**

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr) / [2,000 lb/ton]]

Green House Gas Emissions (GHG)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor in lb/hp-hr</th>
<th>Potential Emission in tons/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>1.15E+00</td>
<td>1.54E+03</td>
</tr>
<tr>
<td>CH4</td>
<td>4.63E-05</td>
<td>6.18E-02</td>
</tr>
<tr>
<td>N2O</td>
<td>9.26E-06</td>
<td>1.24E-02</td>
</tr>
</tbody>
</table>

**Summed Potential Emissions in tons/yr 1.54E+03**

CO2e Total in tons/yr 1.54E+03

**Methodology**

CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.

CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr) / [2,000 lb/ton]]

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
Appendix A: Emission Calculations
emergency Generator - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Address City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>direct PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>0.10</td>
<td>0.0573</td>
<td>0.0573</td>
<td>0.500</td>
<td>3.2</td>
<td>0.09</td>
<td>0.85</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>2.96</td>
<td>1.70</td>
<td>1.70</td>
<td>14.82</td>
<td>94.85</td>
<td>2.67</td>
<td>25.19</td>
</tr>
</tbody>
</table>

*No information was given regarding which method was used to determine the PM emission factor or whether condensable PM is included. The PM10 emission factor is filterable and condensable PM10 combined. The PM2.5 emissions were assumed to be equal to PM10.

**NOx emissions: uncontrolled = 3.2 lb/MMBtu, controlled with ignition timing retard = 1.9 lb/MMBtu
Appendix A: Emissions Calculations

Space Heaters

#2 Fuel Oil

Address, City IN Zip: 2791 North US Highway 231, Rockport, Indiana 47635
Permit Number: 147-40656-00020
Reviewer: Mena Mekhail

<table>
<thead>
<tr>
<th>Heat Input Capacity</th>
<th>Potential Throughput</th>
<th>S = Weight % Sulfur</th>
</tr>
</thead>
<tbody>
<tr>
<td>MMBtu/hr</td>
<td>kgals/year</td>
<td>0.3</td>
</tr>
<tr>
<td>20.65</td>
<td>1292.1</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/kgal</td>
<td>2.0</td>
<td>2.3</td>
<td>1.6</td>
<td>42.6</td>
<td>20.0</td>
<td>0.20</td>
<td>5.0</td>
</tr>
</tbody>
</table>

| Potential Emission in tons/yr | 1.3 | 1.5 | 1.0 | 27.5 | 12.9 | 0.1 | 3.2 |

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-02-005-01/02/03) Supplement E 9/98
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/yr) x Emission Factor (lb/kgal)/2,000 lb/ton

See Page 15 for Greenhouse Gas calculations.
Appendix A: Emissions Calculations
Space Heaters
#2 Fuel Oil
HAPs Emissions

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address, City IN Zip:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit Number:** 147-40656-00020  
**Reviewer:** Mena Mekhail

### HAPs - Metals

<table>
<thead>
<tr>
<th>Emission Factor in lb/mmBtu</th>
<th>Arsenic</th>
<th>Beryllium</th>
<th>Cadmium</th>
<th>Chromium</th>
<th>Lead</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4.0E-06</td>
<td>3.0E-06</td>
<td>3.0E-06</td>
<td>3.0E-06</td>
<td>9.0E-06</td>
</tr>
</tbody>
</table>


### HAPs - Metals (continued)

<table>
<thead>
<tr>
<th>Emission Factor in lb/mmBtu</th>
<th>Mercury</th>
<th>Manganese</th>
<th>Nickel</th>
<th>Selenium</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3.0E-06</td>
<td>6.0E-06</td>
<td>3.0E-06</td>
<td>1.5E-05</td>
</tr>
</tbody>
</table>

| Potential Emission in tons/yr | 2.71E-04 | 5.43E-04 | 2.71E-04 | 1.36E-03 |

**Total = 0.004**

**Methodology**

No data was available in AP-42 for organic HAPs.  
Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

See Page 16 for Greenhouse Gas calculations.
Appendix A:  Emissions Calculations

Space Heaters

#2 Fuel Oil

Greenhouse Gas Emissions

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Address, City</td>
<td>2791 North US Highway 231, Rockport, Indiana 47635</td>
</tr>
<tr>
<td>IN Zip:</td>
<td></td>
</tr>
<tr>
<td>Permit Number:</td>
<td>147-29841-00020</td>
</tr>
<tr>
<td>Reviewer:</td>
<td>Ghassan Shalabi</td>
</tr>
<tr>
<td>Date:</td>
<td>07/20/2012</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Greenhouse Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2 Emission Factor in lb/kgals/yr</td>
</tr>
<tr>
<td>CH4</td>
</tr>
<tr>
<td>N2O</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
</tr>
<tr>
<td>CH4</td>
</tr>
<tr>
<td>N2O</td>
</tr>
<tr>
<td>Summed Potential Emissions in tons/yr</td>
</tr>
<tr>
<td>CO2e Total in tons/yr</td>
</tr>
</tbody>
</table>

Methodology

The CO2 Emission Factor for #1 Fuel Oil is 21500. The CO2 Emission Factor for #2 Fuel Oil is 22300. Emission Factors are from AP 42, Tables 1.3-3, 1.3-8, and 1.3-12 (SCC 1-03-005-01/02/03) Supplement E 9/99 (see errata file).

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

SO2 Limit

0.5 lb/MMBtu

Emissions = 45.2235 tpy
The following calculations determine the amount of emissions created by paved roads, based on 8760 hours of use and AP-42, Ch 13.2.1 (Updated, 1/11).

\[ E = \left[ k(sL)^{0.91}(W)^{1.02}\right] \]

<table>
<thead>
<tr>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>K=</td>
<td>0.011</td>
<td>0.0022</td>
</tr>
<tr>
<td>sL=</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>W=</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>E=</td>
<td>2.81</td>
<td>0.56</td>
</tr>
</tbody>
</table>

### Methodology:

Throughput is based on the limit of 35,040 tpy of AC

Truck capacity for AC is 20 tons

1. Trips/Hour = Throughput (tons/hr)/Truck capacity (tons)
2. Miles/year = trip/hr*mile/trip*8760 hr/year
3. Uncontrolled PTE (tons/year) = EF(lb/mile)*Miles/year*ton/2000lbs
4. Controlled PTE (tons/year) = Uncontrolled PTE (tons/year) * (1-control efficiency/100)
Technical Support Document - Appendix A - Emission Calculations
Material Handling Operation

Address: 2791 North US Highway 231, Rockport, Indiana 47635
Permit No.: 147-40656-00020
Reviewer: Mena Mekhail

<table>
<thead>
<tr>
<th></th>
<th>Coal Unloading</th>
<th>Coal Conveyance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Throughput (TPY)</td>
<td>10,458,044</td>
<td>2,751,984</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>k</td>
<td>0.740</td>
<td>0.740</td>
<td>0.740</td>
</tr>
<tr>
<td>PM</td>
<td>0.350</td>
<td>0.350</td>
<td>0.350</td>
</tr>
<tr>
<td>PM10</td>
<td>0.053</td>
<td>0.053</td>
<td>0.053</td>
</tr>
<tr>
<td>PM2.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>U - Conveyor Speed (MPH)</td>
<td>8</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>M - Moisture %</td>
<td>6.90</td>
<td>6.90</td>
<td></td>
</tr>
<tr>
<td>PM Emission Factor (lb/ton)</td>
<td>0.00077</td>
<td>0.00077</td>
<td></td>
</tr>
<tr>
<td>PM10 Emission Factor (lb/ton)</td>
<td>0.00036</td>
<td>0.00036</td>
<td></td>
</tr>
<tr>
<td>PM2.5 Emission Factor (lb/ton)</td>
<td>0.00006</td>
<td>0.00006</td>
<td></td>
</tr>
<tr>
<td>Transfer Points</td>
<td>2.0</td>
<td>8.0</td>
<td></td>
</tr>
</tbody>
</table>

**Methodology:**

\[
\text{Emission Factor} = (k)(0.0032)[(U/5)^{1.3}/(M/2)^{1.4}] \text{, AP-42, Chapter 13.2.4, 11/06}
\]

\[
\text{PTE} = \text{Emission Factor (lb/ton)} \times \text{Throughput (ton/yr)} \times \text{Transfer Points} \times \left( \frac{1 \text{ ton}}{2,000 \text{ lb}} \right)
\]

Assume 90% control efficiency

<table>
<thead>
<tr>
<th></th>
<th>Uncontrolled PTE (TPY)</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM PTE (ton/yr)</td>
<td>8.05</td>
<td>8.48</td>
</tr>
<tr>
<td>PM10 PTE (ton/yr)</td>
<td>3.76</td>
<td>3.96</td>
</tr>
<tr>
<td>PM2.5 PTE (ton/yr)</td>
<td>0.63</td>
<td>0.66</td>
</tr>
</tbody>
</table>

**Controlled PTE (TPY):**

1.65
0.77
0.13
Technical Support Document - Appendix A - Emission Calculations

Fly Ash Handling Operations

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit No.:** 147-40656-00020  
**Reviewer:** Mena Mekhail

Maximum Filling Rate: 116.00 ton/hr  
Maximum Daily Ash Production: 1,373.00 ton/day  
Maximum Hours of Operation: 11.84 hr/day

### PM Emissions

<table>
<thead>
<tr>
<th>Process</th>
<th>Max Throughput (tons/hr)</th>
<th>Emission Factor (lb/ton)</th>
<th>Transfer Points</th>
<th>PTE (lb/hr)</th>
<th>PTE (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 Storage Silos for MB1</td>
<td>58.00</td>
<td>3.14</td>
<td>5.00</td>
<td>910.60</td>
<td>1,966.99</td>
</tr>
<tr>
<td>4 Storage Silos for MB2</td>
<td>58.00</td>
<td>3.14</td>
<td>5.00</td>
<td>910.60</td>
<td>1,966.99</td>
</tr>
<tr>
<td>Tanker Trucks loading MB1</td>
<td>300.00</td>
<td>0.61</td>
<td>4.00</td>
<td>732.00</td>
<td>3,206.16</td>
</tr>
<tr>
<td>Tanker Trucks loading MB2</td>
<td>300.00</td>
<td>0.61</td>
<td>4.00</td>
<td>732.00</td>
<td>3,206.16</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td></td>
<td>2,553.20</td>
<td>7,140.15</td>
</tr>
</tbody>
</table>

### PM10/2.5 Emissions

<table>
<thead>
<tr>
<th>Process</th>
<th>Max Throughput (tons/hr)</th>
<th>Emission Factor (lb/ton)</th>
<th>Transfer Points</th>
<th>PTE (lb/hr)</th>
<th>PTE (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 Storage Silos for MB1</td>
<td>58.00</td>
<td>1.10</td>
<td>5.00</td>
<td>319.00</td>
<td>689.07</td>
</tr>
<tr>
<td>4 Storage Silos for MB2</td>
<td>58.00</td>
<td>1.10</td>
<td>5.00</td>
<td>319.00</td>
<td>689.07</td>
</tr>
<tr>
<td>Tanker Truck loading</td>
<td>600.00</td>
<td>0.61</td>
<td>4.00</td>
<td>1,464.00</td>
<td>6,412.32</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td>2,102.00</td>
<td>7,790.47</td>
</tr>
</tbody>
</table>
Technical Support Document - Appendix A - Emission Calculations

Fly Ash Handling Operations

Address: 2791 North US Highway 231, Rockport, Indiana 47635
Permit No.: 147-40656-00020
Reviewer: Mena Mekhail

<table>
<thead>
<tr>
<th>PTE HAP</th>
<th>HAP Concentration (ppm)</th>
<th>PTE HAP (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arsenic</td>
<td>52</td>
<td>0.371</td>
</tr>
<tr>
<td>Beryllium</td>
<td>3</td>
<td>0.02</td>
</tr>
<tr>
<td>Cadmium</td>
<td>4</td>
<td>0.03</td>
</tr>
<tr>
<td>Chromium</td>
<td>39</td>
<td>0.28</td>
</tr>
<tr>
<td>Cobalt</td>
<td>8</td>
<td>0.06</td>
</tr>
<tr>
<td>Lead</td>
<td>22</td>
<td>0.16</td>
</tr>
<tr>
<td>Manganese</td>
<td>59</td>
<td>0.421</td>
</tr>
<tr>
<td>Mercury</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>Nickel</td>
<td>32</td>
<td>0.23</td>
</tr>
<tr>
<td>Total HAP (TPY)</td>
<td></td>
<td>1.56</td>
</tr>
</tbody>
</table>

Methodology:
1) PTE (lb/hr) = emission factor (lb/ton) x throughput (ton/hr)
2) PTE (TPY) = PTE (lb/hr) x operation hr/yr x 1 ton/2,000 lb
   Silos - 4320 hr/yr
   Tanker Truck Loading - 8,760 hr/yr
3) Limited PTE is from the PSD Minor Limit
4) PTE HAP (TPY) = PTE PM (TPY) x HAP concent. (ppm) / 1,000,000
5) Limited PTE HAP (TPY) = Limited PTE PM x HAP concent (ppm) / 1,000,000

Notes:
1) Ash silos emission factors are from AP-42, Table 11.12-2, 10/2001, pneumatic conveyance of cement.
2) Tanker Truck Loading emission factor is from AP-42, Table 11.17-4, for lime loadout.
3) 5 transfer points are shown for each 4 Silos.
Technical Support Document - Appendix A - Emission Calculations

Fly Ash Handling Operations

Address: 2791 North US Highway 231, Rockport, Indiana 47635
Permit No.: 147-40656-00020
Reviewer: Mena Mekhail

Fly Ash Handling Operations - Continued

326 IAC 6-3-2 Emission Limit Calculation

<table>
<thead>
<tr>
<th>Process</th>
<th>Max Throughput (tons/hr)</th>
<th>Uncontrolled PTE (lb/hr)</th>
<th>326 IAC 6-3-2 Limit (lb/hr) *</th>
<th>326 IAC 6-3-2 limit (tpy)</th>
<th>Controlled Emissions (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 Storage Silos for MB1</td>
<td>58.00</td>
<td>910.60</td>
<td>45.97</td>
<td>201.35</td>
<td>1.97</td>
</tr>
<tr>
<td>4 Storage Silos for MB2</td>
<td>58.00</td>
<td>910.60</td>
<td>45.97</td>
<td>201.35</td>
<td>1.97</td>
</tr>
<tr>
<td>Tanker Tuck Loading for MB1</td>
<td>300.00</td>
<td>732.00</td>
<td>63.00</td>
<td>275.94</td>
<td>80.15</td>
</tr>
<tr>
<td>Tanker Tuck Loading for MB2</td>
<td>300.00</td>
<td>732.00</td>
<td>63.00</td>
<td>275.94</td>
<td>80.15</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>678.64</strong></td>
<td><strong>84.09</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Storage Silos require a control device to comply with 326 IAC 6-3-2.

* Process Weight Rates in excess of 60,000 lb/hr

\[ E = [55 \times (P)^{0.11}] - 40 \]

Where: \( E \) = Allowable Emission Rate for PM (lb/hr)

\( P \) = Process Weight Rate (tons/hr)
Technical Support Document - Appendix A - Emission Calculations

Coal Storage Pile - Wind Erosion

Address: 2791 North US Highway 231, Rockport, Indiana 47635
Permit No.: 147-40656-00020
Reviewer: Mena Mekhail

\[ A = \text{Storage Area} \quad 53.50 \quad \text{acres} \]
\[ s = \text{Coal Silt Content} \quad 6.50 \quad \text{wt \%} \]
\[ p = \text{Days > 0.01" rain} \quad 125.00 \quad \text{days} \]
\[ f = \text{Days wind > 12 mph} \quad 15.00 \quad \text{days} \]
\[ \text{PM 10 \% of PM} \quad 35.00\% \]

**Emission Factor Calculation**

\[ Ef = 1.7 \times \left( \frac{s}{1.5} \right) \times \left( \frac{365 - p}{235} \right) \times \left( \frac{f}{15} \right) \quad \text{AP-42, Section 11.2.3.3, May 1983, Equation 3} \]

\[ Ef = 7.523 \quad \text{lb/acre/day (Total Suspended Particulate/PM)} \]

**PM/PM10/PM2.5 Emissions**

\[ \text{TSP / PM (ton/yr)} = Ef \times \frac{\text{lb/acre/day}}{\text{A (acres)}} \times 365 \times 1 \times 2000 \quad \text{lb} \]

\[ \text{PM10} = 0.5 \times \text{TSP} \quad \text{(AP-42, Section 13.2.5.3, May 1983)} \]

\[ \text{PM2.5} = 0.15 \times \text{PM10} \quad \text{(AP-42, Section 13.2.5.3, May 1983)} \]

\[ \text{PM / TSP} = 7.523 \times 53.5 \times 365 \times 1/2000 = 73.46 \quad \text{TPY} \]

\[ \text{PM10} = 0.5 \times 73.46 = 36.73 \quad \text{TPY} \]

\[ \text{PM2.5} = 0.15 \times 36.73 = 5.51 \quad \text{TPY} \]
Technical Support Document - Appendix A - Emission Calculations

Uncontrolled PTE Summary (for SSM 32890)

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant  
**Address City IN Zip:** 2791 North US Highway 231, Rockport, Indiana 47635  
**Permit Number:** 147-40656-00020  
**Plant ID:** 147-00020  
**Reviewer:** Mena Mekhail

<table>
<thead>
<tr>
<th>System/Activity</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry Sorbent Injection System</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Truck Traffic (Paved Roads)</td>
<td>11.73</td>
<td>2.23</td>
<td>0.55</td>
</tr>
<tr>
<td>Unloading and Handling</td>
<td>52.01</td>
<td>33.49</td>
<td>0.17</td>
</tr>
<tr>
<td>Total</td>
<td>63.74</td>
<td>35.72</td>
<td>0.72</td>
</tr>
</tbody>
</table>

Net Increase in PTE in the Activated Carbon Injection System

| PTE before modification        | 4.97 | 2.45 | 2.17  |
| PTE after modification         | 14.63 | 8.62 | 1.42  |
| Increase due to the ACI modification | 9.66 | 6.17 | 0.00  |

**Increase in Waste Disposal Activities**

| Increase                  | 26.26 | 8.03 | 0.99  |

**Total increase in the PTE of the modified units**

| Total increase              | 35.92 | 14.20 | 0.99  |

**Total PTE**

| PTE                       | 99.66 | 49.92 | 1.71  |
## 2013 Project Increases

<table>
<thead>
<tr>
<th>Activity</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>VOC</th>
<th>CO</th>
<th>Nox</th>
<th>GHG</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dry Sorbent Injection System</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Truck Traffic (Paved Roads)</td>
<td>2.39</td>
<td>0.46</td>
<td>0.11</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Unloading and Handling</td>
<td>0.05</td>
<td>0.03</td>
<td>0.12</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Limited PTE of DSI</td>
<td>2.44</td>
<td>0.49</td>
<td>0.23</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>74,641.50</td>
</tr>
<tr>
<td><strong>Activated Carbon Injection System</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 pneumatic truck unloading stations, add 2 silos, 8 metering pressure tanks with capacity of 5000 system capacity lb/hr</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Truck Traffic (Paved Roads)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseline</td>
<td>0.00</td>
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<td><strong>ACI Emission Increase</strong></td>
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### Combustion Waste Disposal Activities

<table>
<thead>
<tr>
<th>Activity</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>VOC</th>
<th>CO</th>
<th>Nox</th>
<th>GHG</th>
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<tr>
<td><strong>Ash Handling to Silo</strong></td>
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<td>Baseline</td>
<td>37.13</td>
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<td><strong>Truck Trafic</strong></td>
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<tr>
<td>Baseline</td>
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<td>1.26</td>
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<td><strong>Truck Loading</strong></td>
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<tr>
<td>Baseline</td>
<td>49.92</td>
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<td>0.49</td>
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</tbody>
</table>

**Emission Increase for 2013 project** 59.69 31.39 12.23
Technical Support Document - Appendix A - Emission Calculations

PSD analysis summary table.

**Company Name:** Indiana Michigan Power d.b.a. American Electric Power (AEP) Rockport Plant

**Address City IN Zip:** 2791 North US Highway 231, Rockport, Indiana 47635

**Permit Number:** 147-40656-00020

**Plant ID:** 147-00020

**Reviewer:** Mena Mekhail

Projects during contemporaneous period:

<table>
<thead>
<tr>
<th>Projects during contemporaneous period:</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>VOC</th>
<th>CO</th>
<th>Nox</th>
<th>GHG</th>
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<tr>
<td>ACI 1st Modification Issued July 29, 2010 (Permit # 147-29169-00020)</td>
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<tr>
<td>Injection rate was increased and 4 additional feed meters were added. Therefore, this is considered 1 with the 2008 project</td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>PAC Loading and Storage</td>
<td>3.33</td>
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<td>2.13</td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Paved Roads</td>
<td>1.45</td>
<td>0.28</td>
<td>0.04</td>
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<tr>
<td>Unpaved Roads</td>
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<td>0.05</td>
<td>0.01</td>
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<tr>
<td>New Heater</td>
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<td>0.2</td>
<td>0.2</td>
<td>4.9</td>
<td>0</td>
<td>0.3</td>
<td>1.4</td>
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<tr>
<td><strong>Modified Equipment</strong></td>
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<td></td>
</tr>
<tr>
<td>Boilers (ATPA)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>(2615.65 tpy past actuals and 2118.7 tpy projected actuals)</td>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Injection Rate = 9,198 tpy

Total Increase 5.07 | 2.66 | 2.38 | 4.9 | 0 | 0.3 | 1.4 |

**Boilers MB1 and MB2**

<table>
<thead>
<tr>
<th>Boilers MB1 and MB2</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>VOC</th>
<th>CO</th>
<th>Nox</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline</td>
<td>2620.62</td>
<td>1755.82</td>
<td>759.98</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>2575</td>
<td>1725.25</td>
<td>746.75</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td><strong>Increase in emissions</strong></td>
<td>-45.62</td>
<td>-30.57</td>
<td>-13.23</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Total Contemporaneous Decreases -45.62 | -30.57 | -13.23 | 0 | 0 | 0 | 0 |

**Net Change** (Project 2013 Increase + Contemp. Increases - Contemp. Decreases) 19.26 | 3.63 | 1.53 | 4.90 | 0.02 | 0.61 | 2.63 | 74641.5 |

Significant Level 25 | 15 | 10 | 40 | 40 | 10 | 40 | 75,000 |
The following calculations determine the amount of emissions created by paved roads, based on 8760 hours of use and AP-42, Ch 13.2.1 (Updated, 1/11).

\[ E = [k(sL)^{0.91}*(W)^{1.02}] \]

\( E \) = Emission Factor
\( K \) = particle size multiplier
\( sL \) = Silt Loading

<table>
<thead>
<tr>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>( K )</td>
<td>0.011</td>
<td>0.0022</td>
</tr>
<tr>
<td>( sL )</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>( W )</td>
<td>31.5</td>
<td>31.5</td>
</tr>
<tr>
<td>( E )</td>
<td>3.56</td>
<td>0.71</td>
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</table>

\( g/m^2 \) from table 13.2.1-3 for concrete batching

\( \text{tons} \)

<table>
<thead>
<tr>
<th>Process</th>
<th>Throughput (tons/hr)</th>
<th>Trips/hr (^1)</th>
<th>Mile/Trip</th>
<th>Miles/Year (^2)</th>
<th>Uncontrolled PTE PM (tons/yr) (^3)</th>
<th>Uncontrolled PTE PM10 (tons/yr) (^3)</th>
<th>Uncontrolled PTE PM2.5 (tons/yr) (^3)</th>
<th>Control Efficiency%</th>
<th>Controlled PTE PM (tons/yr) (^4)</th>
<th>Controlled PTE PM10 (tons/yr) (^4)</th>
<th>Controlled PTE PM2.5 (tons/yr) (^4)</th>
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</thead>
<tbody>
<tr>
<td>SI-All Units</td>
<td>16.26</td>
<td>0.813</td>
<td>0.88</td>
<td>6267.25</td>
<td>11.73</td>
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<td>0.55</td>
<td>79.6</td>
<td>2.39</td>
<td>0.46</td>
<td>0.11</td>
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</table>

Controlled Emissions (lb/1000ton) 33.58 6.39 1.57

Methodology:
Throughput is based on the limit of 142,500 tpy of Sodium Bicarbonate
Truck capacity for SI is 20 tons
\(^1\)Trips/Hour = Throughput (tons/hr)/Truck capacity (tons)
\(^2\)Miles/year = trip/hr*mile/trip*8760 hr/year
\(^3\)Uncontrolled PTE (tons/year) = EF(lb/mile)*Miles/year*ton/2000lbs
\(^4\)Controlled PTE (tons/year) = Uncontrolled PTE (tons/year) * (1-control efficiency/100)
Controls are required as specified in Fugitive Dust Plan
DSI System
PTE for Unload and Handling

Truck unloading into the Silo:

Throughput = 50 tph per silo
Throughput = 142,500 tpy = 142.5 kton/yr

Uncontrolled

<table>
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<tr>
<th>Emission Factor (lb/ton)</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5 **</th>
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<tbody>
<tr>
<td></td>
<td>0.73</td>
<td>0.47</td>
<td>0.0024</td>
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</table>

| Emissions (tpy) | 52.01 | 33.49 | 0.17 |
| Emissions (lb/hr)| 36.50 | 23.50 | 0.12 |
| For both units (lb/hr) | 73.00 | 47.00 | 0.24 |

Controlled by Bin Vent Filter (099.9 % control efficiency)

<table>
<thead>
<tr>
<th>Controlled Emission Factor (lb/kton)</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>0.73</td>
<td>0.47</td>
<td>0.0024</td>
</tr>
</tbody>
</table>

| Emissions (tpy) | 0.052 | 0.033 | 0.0002 |
| Emissions (lb/hr)| 0.037 | 0.024 | 0.0001 |
| For both units (lb/hr) | 0.07300 | 0.04700 | 0.00024 |

* from Table 11.12-2 in AP-42 (Cement Loading into storage silos)
** Based on samples collected during test conducted in fall of 2011. PM2.5 = 0.005PM10
Controlled Emission Factor (lb/kton) = Emission Factor (lb/ton) * 1000 (ton/kton)*(1-.999)
Source Description and Location

Source Name: Indiana Michigan Power Company, dba American Electric Power - Rockport Plant
Source Location: 2791 N. U.S. Highway 321, Rockport, IN 47635
County: Spencer
SIC Code: 4911 (Electric Services)
Permit Renewal No.: T147-40656-00020
Permit Reviewer: Mena Mekhail


Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. 147-29841-00020 on August 15, 2014. The source has since received the following approvals:

(a) Significant Permit Modification No. 147-34888-00020, issued on February 20, 2015;
(b) Significant Permit Modification No. 147-35785-00020, issued on July 30, 2015;
(c) Significant Permit Modification No. 147-36090-00020, issued on November 9, 2015;
(d) Significant Permit Modification No. 147-37926-00020, issued on May 1, 2017;
(e) Significant Permit Modification No. 147-38415-00020, issued on May 21, 2018;
(f) Significant Source Modification No. 147-41576-00020, issued on September 11, 2019; and
(g) Significant Permit Modification No. 147-41578-00020, issued on.

The source submitted an application for a Part 70 Operating Permit Renewal on October 31, 2018. At this time, the application is under review.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units:

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of
particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(c) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

(d) A coal storage and handling system for MB1 and MB2, with installation started in 1981 and completed in 1984, consisting of the following equipment:

1. Two (2) barge unloading stations, identified as Stations 1 and 2, each with a baghouse, or a dust extraction system using water injection, and foam or water spray for particulate control, each with a bucket elevator with foam or water spray and partial enclosure for particulate control, and Conveyors 1 and 2 with water spray for particulate control.

2. Enclosed conveyor systems, including fully and partially enclosed conveyors, with foam, water, or other equivalent dust suppression measures for particulate control, with the transfer points enclosed by buildings with baghouses, or a dust extraction system using water injection, for particulate control at Stations 5, 6 and 7. A stacker reclaim system is used to drop coal to the storage pile(s). The coal handling system has a design throughput capacity of 4000 tons per hour up to the stacker-reclaimers, and 1600 tons per hour from Station 7E and 7W to the coal bunkers in the units.

3. Coal storage pile(s), with fugitive dust emissions controlled by watering.
(4) Coal crushing Station 8, with a maximum throughput of 2618 tons per hour for the east system and 2542 tons per hour for the west system, with a baghouse for particulate control, or a dust extraction system using water injection.

(5) Blending and transfer Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

(6) Blending and transfer Station 10.

(7) Two (2) storage silos for Station 9, with foam, water, or other equivalent dust suppression measures for particulate control.

(8) Coal sampling and transfer Stations A and D, each with a baghouse for particulate control, or a dust extraction system using water injection.

(9) Bunkering conveyors AB, BC, CB, DC, and FD, each fully enclosed, each with a baghouse for particulate control, or a dust extraction system using water injection.

(10) Fourteen (14) storage silos for Unit 1, with particulate control as follows:

(A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 1, or

(B) one or more dust extraction systems using water injection.

(11) Fourteen (14) storage silos for Unit 2, with particulate control as follows:

(A) four (4) bag type filters, two for each set of seven bunkers on each side of Main Boiler 2, or

(B) one or more dust extraction systems using water injection.

(e) Dry fly ash handling:

(1) Fly ash handling for MB1, installed in approximately 1982, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by a bin vent filter on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.

(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.
(2) Fly ash handling for MB2, with installation completed in 1986, including the following:

(A) Vacuum system to convey fly ash to four (4) storage silos with particulate emissions controlled by two (2) bin vent filters on each silo, with a maximum throughput rate of 58 tons per hour.

(B) Each of the four fly ash silos is equipped with two telescoping chutes for loading dry ash into tanker trucks. Each chute has a vacuum system to control dust and transport it back into the storage silo. Process rate for loading the tanker trucks is estimated at 300 tons per hour.

(C) Each of the four fly ash silos is equipped with two wet ash conditioners, for loading ash into open trucks for disposal. Dust is controlled by mixing water with the ash prior to depositing the ash in the truck. Process rate is estimated at 150 tons per hour.

(D) Water spray curtains on each silo can be used to prevent dust generated in the loading operation from leaving the loading gallery in the silo base, if the outdoor temperature is above freezing.

(3) One (1) fly ash barge loading facility, with pneumatic unloading system from covered truck to covered barge with a maximum throughput rate of 52.5 tons ash per hour, with a baghouse on a river cell for particulate control.

(4) Rail loading equipment associated with the former fly ash temporary storage facility, with a maximum throughput rate of 52.5 tons ash per hour. The loader has a baghouse for dust control.

PAC Handling and Storage Operations

(f) Four (4) pneumatic truck unloading stations, two (2) at each set of silos, for transferring halogenated and non-halogenated activated carbon from transports to storage silos, permitted in 2008, 2010, and 2013 with particulate emissions controlled by a bin vent filter.

(g) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2008, 2010, and 2013 with particulate emissions from each silo controlled by a bin vent filter.

(h) Two (2) silos for storing halogenated or non-halogenated activated carbon, each with a maximum storage capacity of 360 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(i) Four (4) metering pressure tanks per silo, with a maximum system capacity of injecting 4000 pounds per hour of halogenated or non-halogenated activated carbon into the exhaust ductwork, permitted in 2008, 2010, and 2013 with particulate emissions from the pressure tanks controlled via the silo bin vent filter.

DSI Handling and Storage operation

(j) Two (2) pneumatic truck unloading systems (one system per unit) for transferring sodium bicarbonate from up to two transport trucks simultaneously to the attached storage silos, permitted in 2013, with particulate emissions controlled by a bin vent filter on the silo receiving the sorbent being unloaded.
(k) Four (4) silos, two (2) per unit, for storing sodium bicarbonate, each with a maximum storage capacity of 1440 tons, permitted in 2013, with particulate emissions from each silo controlled by a bin vent filter.

(l) Injection metering system that includes three (3) metering feeders directly fed from each storage silo, blowers, and piping necessary to inject up to 10 tons per hour of sodium bicarbonate into the ductwork feeding the four electrostatic precipitators on each unit, permitted in 2013, with particulate emissions controlled by a bin vent filter.

### Insignificant Activities

The source also consists of the following insignificant activities:

(a) Space heaters using the following fuels: Fuel oil-fired combustion sources with heat input equal to or less than two million (2,000,000) Btu per hour and firing fuel containing less than three-tenths (0.3) percent sulfur by weight, including space heaters WHU-1 and WHU-2, each with 1.1 MMBtu/hr heat input capacity.

Emergency generators as follows: Diesel generators not exceeding 1600 horsepower.

(b) Degreasing operations that do not exceed 145 gallons per 12 months.

(c) Cleaners and solvents characterized as follows:

1. Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;
2. Having a vapor pressure equal to or less than 0.7 kPa; 5mm Hg; or 0.1 psi measured at 20°C (68°F); the use of which for all cleaners and solvents combined does not exceed 145 gallons per 12 months.

(d) Coal bunker and coal scale exhausts and associated dust collector vents.

   [This is an affected unit under 40 CFR 60, Subpart Y]

(e) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO2 5 pounds per hour or 25 pounds per day, NOx 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

   Ponded bottom ash handling and management, including dredging bottom ash ponds and loading material into trucks.

(f) Wet process bottom ash handling, with hydroveyors conveying ash to storage ponds, with water level sufficient to prevent ash re-entrainment.

(g) Emergency generators as follows: Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, constructed in 1983/1984, each with 25.16 MMBtu/hr heat input capacity.

   [These are affected units under 40 CFR 63, Subpart ZZZZ]

(h) Five (5) No. 2 fuel oil-fired space heaters designated as WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9, with heat input capacities of 4.5 MMBtu/hr, 3.0 MMBtu/hr, 2.75 MMBtu/hr, 3.5 MMBtu/hr, and 4.5 MMBtu/hr, respectively.
(i) One (1) No. 2 fuel oil-fired space heater, identified as WHU-10, approved in 2018 for construction, with heat input capacity of 2.4 MMBtu/hr.

(j) Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.

[These are affected units under 40 CFR 60, Subpart IIII]
[These are affected units under 40 CFR 63, Subpart ZZZZ]

### Enforcement Issue

There are no enforcement actions pending.

### Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

### County Attainment Status

The source is located in Spencer County.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>Better than national standards.</td>
</tr>
<tr>
<td>CO</td>
<td>Unclassifiable or attainment effective November 15, 1990.</td>
</tr>
<tr>
<td>O₃</td>
<td>Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.¹</td>
</tr>
<tr>
<td>PM₂.₅</td>
<td>Unclassifiable or attainment effective April 15, 2015, for the 2012 annual PM₂.₅ standard.</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>Unclassifiable effective November 15, 1990.</td>
</tr>
<tr>
<td>NO₂</td>
<td>Unclassifiable or attainment effective January 29, 2012, for the 2010 NO₂ standard.</td>
</tr>
<tr>
<td>Pb</td>
<td>Unclassifiable or attainment effective December 31, 2011.</td>
</tr>
</tbody>
</table>

¹Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.

(a) Ozone Standards
Volatil organic compounds (VOC) and Nitrogen Oxides (NOₓ) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOₓ emissions are considered when evaluating the rule applicability relating to ozone. Spencer County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOₓ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) PM₂.₅
Spencer County has been classified as attainment for PM₂.₅. Therefore, direct PM₂.₅, SO₂, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Spencer County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.
Fugitive Emissions

Since this source is classified as a stationary electric utility generating station, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of Utility Air Regulatory Group v. EPA, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court’s decision. U.S. EPA’s guidance states that U.S. EPA will no longer require PSD or Title V permits for sources “previously classified as ‘Major’ based solely on greenhouse gas emissions.”

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

<table>
<thead>
<tr>
<th>Unrestricted Potential Emissions (ton/year)</th>
<th>PM¹</th>
<th>PM₁₀¹</th>
<th>PM₂.₅¹,₂</th>
<th>SO₂</th>
<th>NOₓ</th>
<th>VOC</th>
<th>CO</th>
<th>Single HAP³</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total PTE of Entire Source Including Fugitives*</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;10</td>
<td>&gt;10</td>
<td>&gt;25</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
<td>NA</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>10</td>
<td>25</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>--</td>
<td>--</td>
</tr>
</tbody>
</table>

¹Under the Part 70 Permit program (40 CFR 70), PM₁₀ and PM₂.₅, not particulate matter (PM), are each considered as a "regulated air pollutant."
²PM₂.₅ listed is direct PM₂.₅.
³Single highest source-wide HAP
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM₁₀, PM₂.₅, SO₂, NOₓ, VOC, and CO is equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(30)) of a
A combination of HAPs is equal to or greater than twenty-five (25) tons per year. The source will be issued a Part 70 Operating Permit Renewal.

### Actual Emissions

The following table shows the actual emissions as reported by the source. This information reflects the 2017 OAQ emission data.

<table>
<thead>
<tr>
<th>Actual Emissions (tons/year)</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Lead (Pb)*</th>
<th>Ammonia (NH3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>230</td>
<td>82</td>
<td>20,784</td>
<td>11,268</td>
<td>183</td>
<td>1,531</td>
<td>0.05</td>
<td>3</td>
<td></td>
</tr>
</tbody>
</table>

*Lead and lead compounds, including any unique chemical substance that contains lead.

### Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

### Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

<table>
<thead>
<tr>
<th>Process/ Emission Unit</th>
<th>Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td>MB 1 and MB2*</td>
<td>2,575.00</td>
</tr>
<tr>
<td>Auxiliary Boilers</td>
<td>75.46</td>
</tr>
<tr>
<td>DG1, DG2, and DG3</td>
<td>1.89</td>
</tr>
<tr>
<td>DFP-1 &amp; DFP-2</td>
<td>5.88</td>
</tr>
<tr>
<td>Space Heater</td>
<td>1.40</td>
</tr>
<tr>
<td>PAC handling and transfer</td>
<td>0.99</td>
</tr>
<tr>
<td>Coal Handling</td>
<td>16.53</td>
</tr>
<tr>
<td>DSI</td>
<td>0.05</td>
</tr>
<tr>
<td>Fly Ash</td>
<td>58.40</td>
</tr>
<tr>
<td>Coal Storage</td>
<td>73.46</td>
</tr>
<tr>
<td>Process/Emission Unit</td>
<td>PM</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-----</td>
</tr>
<tr>
<td>Fugitives (unpaved roads)**</td>
<td>27.17</td>
</tr>
<tr>
<td>Fugitives (paved roads)***</td>
<td>30.76</td>
</tr>
<tr>
<td>Total PTE of Entire Source</td>
<td>&gt;100</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
<td>NA</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
<td>100</td>
</tr>
</tbody>
</table>

1Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a "regulated air pollutant."
2PM2.5 listed is direct PM2.5.
3Single highest source-wide HAP.
4Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant, PM, PM10, PM2.5, SO2, NOx, VOC, and CO, is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability

Federal rule applicability for this source has been reviewed as follows:

**New Source Performance Standards (NSPS):**

(a) Boilers MB1, MB2, and Auxiliary Boilers 1 and 2 are still subject to the New Source Performance Standard for Fossil -Fuel-Fired Generators for Which Construction is Commenced After August 17, 1971, (40 CFR 60, Subpart D), which is incorporated by reference as 326 IAC 12, because construction of these units commenced in 1977, and each has a design heat input rate greater than 250 MMBTU/hr (12,374 MMBTU/hr each for MB1 and MB2, and 603 MMBTU/hr each for the auxiliary boilers). The boilers subject to this rule is as follows:

1 One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control.
No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOX) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(2) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

(3) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12.

The Boilers, identified as MB1, MB2, and Auxiliary Boilers 1 and 2 are subject to the following portions of 40 CFR 60, Subpart D.

1. 40 CFR 60.40
2. 40 CFR 60.41
3. 40 CFR 60.42
4. 40 CFR 60.43(a) and (b)
5. 40 CFR 60.44(a) and (b)
6. 40 CFR 60.45
7. 40 CFR 60.46

(b) The two (2) Diesel Fire Pumps, Identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each are subject to the New Source Performance Standard 326 IAC 12, 40 CFR 60, Subpart III (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines) because these units were constructed after July 11, 2005 and manufactured after April 1, 2006, which is the applicability date for the rule. The emission units subject to this rule is as follows:
(1) Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.

These units are subject to the following portions of 40 CFR 60, Subpart III:

(1) 40 CFR 60.4202
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4207(a) & (b)
(4) 40 CFR 60.4209(a)
(5) 40 CFR 60.4211(a),(c) & (e)
(6) 40 CFR 60.4214(b)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the G-1 except as otherwise specified in 40 CFR 60, Subpart III.

Based on this evaluation, this source is subject to 40 CFR 60, Subpart III. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 60.4211(f)(2)(ii) - (iii) of NSPS Subpart III. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA’s Guidance Memo: [https://www3.epa.gov/airtoxics/icengines/docs/RICEVacaturGuidance041516.pdf](https://www3.epa.gov/airtoxics/icengines/docs/RICEVacaturGuidance041516.pdf)

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as strikethrough text. At this time, IDEM is not making any changes to the permit’s attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 60.4211(f)(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

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

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

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

(c) The Coal Handling System is still subject to the New Source Performance Standard for Coal Preparation Plants, 40 CFR60, Subpart Y, which is incorporated by reference as 326 IAC 12,
because the operations include one or more crushers and the facilities were installed after
the applicability date of October 24, 1974.

(1) A coal storage and handling system for MB1 and MB2, with installation started in 1981
and completed in 1984, consisting of the following equipment:

(A) Two (2) barge unloading stations, identified as Stations 1 and 2, each with a
baghouse, or a dust extraction system using water injection, and foam or water
spray for particulate control, each with a bucket elevator with foam or water spray
and partial enclosure for particulate control, and Conveyors 1 and 2 with water
spray for particulate control.

(B) Enclosed conveyor systems, including fully and partially enclosed conveyors,
with foam, water, or other equivalent dust suppression measures for particulate
control, with the transfer points enclosed by buildings with baghouses, or a dust
extraction system using water injection, for particulate control at Stations 5, 6 and
7. A stacker reclaim system is used to drop coal to the storage pile(s). The coal
handling system has a design throughput capacity of 4000 tons per hour up to
the stacker-reclaimers, and 1600 tons per hour from Station 7E and 7W to the
c coal bunkers in the units.

(C) Coal storage pile(s), with fugitive dust emissions controlled by watering.

(D) Coal crushing Station 8, with a maximum throughput of 2618 tons per hour for
the east system and 2542 tons per hour for the west system, with a baghouse for
particulate control, or a dust extraction system using water injection.

(E) Blending and transfer Station 9, with foam, water, or other equivalent dust
suppression measures for particulate control.

(F) Blending and transfer Station 10.

(G) Two (2) storage silos for Station 9, with foam, water, or other equivalent dust
suppression measures for particulate control.

(H) Coal sampling and transfer Stations A and D, each with a baghouse for
particulate control, or a dust extraction system using water injection.

(I) Bunkering conveyors AB, BC, CB, DC, and FD, each fully enclosed, each with a
baghouse for particulate control, or a dust extraction system using water
injection.

(J) Fourteen (14) storage silos for Unit 1, with particulate control as follows:

(1) four (4) bag type filters, two for each set of seven bunkers on each side
of Main Boiler 1, or

(2) one or more dust extraction systems using water injection.

(K) Fourteen (14) storage silos for Unit 2, with particulate control as follows:

(1) four (4) bag type filters, two for each set of seven bunkers on each side
of Main Boiler 2, or

(2) one or more dust extraction systems using water injection.

(L) Coal bunker and coal scale exhausts and associated dust collector vents.
The Coal Handling System is subject to the following portions of 40 CFR 60, Subpart Y.

1. 40 CFR 60.250
2. 40 CFR 60.251
3. 40 CFR 60.252(a)(1) and (2)
4. 40 CFR 60.252(b)(1) and (2)
5. 40 CFR 60.252(c)
6. 40 CFR 60.253(a)(1)
7. 40 CFR 60.253(a)(2)(i) and (ii)
8. 40 CFR 60.253(b)
9. 40 CFR 60.254

(d) The three (3) No. 2 fuel oil-fired emergency diesel generators and two (2) Diesel Fire Pumps are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ and 326 IAC 20-82, because these units are located in a major source of HAPs. The units subject to this rule include the following:

1. Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, each with 25.16 MMBtu/hr heat input capacity.
2. Two (2) Diesel Fire Pumps, identified as DFP-1 and DFP-2, constructed in 2013 and 2014, respectively, with a maximum capacity of 305 HP each.

The engines identified as DG1, DG2, DG3, DFP-1, and DFP-2 are subject to the following portions of 40 CFR 63, Subpart ZZZZ.

1. 40 CFR 63.6585
2. 40 CFR 63.6590(b)(3)(iii)
3. 40 CFR 63.6640(f)(2)

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart ZZZZ.

Based on this evaluation, this source is subject to 40 CFR 63, Subpart ZZZZ. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA’s Guidance Memo: https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as strikethrough text. At this time, IDEM is not making any changes to the permit’s attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

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

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

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

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(e) The two (2) pulverized coal opposed wall fired dry bottom boilers, identified as MB1 and MB2, are subject to the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR 63.9980, Subpart UUUUU). MB1 and MB2 received an Order of the Commissioner granting a compliance extension for 40 CFR Part 63, Subpart UUUUU. MB1 and MB2 shall comply with the standards set forth in 40 CFR Part 63, Subpart UUUUU no later than December 16, 2015.

The two (2) pulverized coal opposed wall fired dry bottom boilers, identified as MB1 and MB2 are subject to the following portions of 40 CFR 63, Subpart UUUUU:

1. 40 CFR 63.9980
2. 40 CFR 63.9981
3. 40 CFR 63.9982(a)(1) and (d)
4. 40 CFR 63.9984(b), (c), and (f)
5. 40 CFR 63.9991(a)
6. 40 CFR 63.10000(a), (b), (c), (d), (e), and (l)
7. 40 CFR 63.10005(a), (b), (d), (e), (f), (h), (j), and (k)
8. 40 CFR 63.10006(b), (d), (f), (h), (i)(1), and (j)
9. 40 CFR 63.10007(a), (b), (d), (e), and (g)
10. 40 CFR 63.10009(k) and (m)
11. 40 CFR 63.10010(a)(2)(ii), (b), (c), (d), (g), and (l)
12. 40 CFR 63.10011(a), (c)(1), (d), (e), and (g)
13. 40 CFR 63.10020
14. 40 CFR 63.10021
15. 40 CFR 63.10030
16. 40 CFR 63.10031
17. 40 CFR 63.10032
18. 40 CFR 63.10033
19. 40 CFR 63.10040
20. 40 CFR 63.10041
21. 40 CFR 63.10042
22. Table 2 to 40 CFR 63, Subpart UUUUU
23. Table 3 to 40 CFR 63, Subpart UUUUU
24. Table 5 to 40 CFR 63, Subpart UUUUU
25. Table 7 to 40 CFR 63, Subpart UUUUU
26. Table 8 to 40 CFR 63, Subpart UUUUU
27. Table 9 to 40 CFR 63, Subpart UUUUU
The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart UUUUU.

(f) The National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD, was initially promulgated on September 13, 2004. On June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the standards. New rule amendments were promulgated on March 21, 2011 (76 FR 15608). On May 18, 2011, the EPA issued a delay of the effective dates for Subpart DDDDD until the proceedings for judicial review of the rules were completed or the EPA completed its reconsideration of the rule, whichever was earlier (76 FR 28662). On January 9, 2012, the US District Court for the District of Columbia issued an order (Sierra Club vs. U.S. EPA, No. 11-1278) to vacate and remand the Delay Notice issued on May 18, 2011. Therefore, the provisions of 40 CFR 63, Subpart DDDDD, as issued on March 21, 2011 are effective and shall be included in the permit as applicable.

The two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2 are subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63.7485, Subpart DDDDD. The units subject to this rule includes the following:

(1) Two (2) No. 2 fuel oil-fired boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2, with construction commenced in 1977 and completed in 1983, each with a design heat input capacity of 603 million Btu per hour, both exhausting through Stack AB12. [40 CFR 63, Subpart DDDDD]

These emission units are subject to the following portions of 40 CFR 63, Subpart DDDDD:

(1) 40 CFR 63.7485
(2) 40 CFR 63.7490(a)(1)
(3) 40 CFR 63.7490(d)
(4) 40 CFR 63.7495(b)
(5) 40 CFR 63.7499(o)
(6) 40 CFR 63.7500(c)
(7) 40 CFR 63.7500(f)
(8) 40 CFR 63.7501
(9) 40 CFR 63.7505(a)
(10) 40 CFR 63.7515(d)
(11) 40 CFR 63.7525(k)
(12) 40 CFR 63.7540(a)
(13) 40 CFR 63.7540(a)(12)
(14) 40 CFR 63.7550(b)
(15) 40 CFR 63.7550(c)(1)
(16) 40 CFR 63.7550(c)(5)(i) through (iv)
(17) 40 CFR 63.7550(c)(5)(xiv)
(18) 40 CFR 63.7550(h)(3)
(19) 40 CFR 63.7555(a)(1)
(20) 40 CFR 63.7555(i)
(21) 40 CFR 63.7555(j)
(22) 40 CFR 63.7560
(23) 40 CFR 63.7575

The provisions of 40 CFR 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63, Subpart DDDDD.
**Cross State Air Pollutant Rule (CSAPR)**

The preamble of the CSAPR regulations promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR Part 70 and 71. The requirements of the Cross-State Air Pollution Rule (CSAPR) apply to the two (2) simple cycle natural gas fired combustion turbines, identified as Units 1 and 2.

**Transport Rule (TR) Trading Program Title V Requirements**

**Description of TR Monitoring Provisions**

The TR subject unit(s), and the unit-specific monitoring provisions at this source, are identified in the following table(s). These unit(s) are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season Trading Program and TR SO2 Group 1 Trading Program.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO2 monitoring) and 40 CFR part 75, subpart H (for NOx monitoring)</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
<th>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</th>
<th>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19</th>
<th>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>x</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td>NOx</td>
<td>x</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td>Heat input</td>
<td>x</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
</tr>
</tbody>
</table>

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<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
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</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td></td>
<td>-------</td>
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</tr>
<tr>
<td>NOx</td>
<td></td>
<td>-------</td>
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<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td>Heat input</td>
<td></td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
</tr>
</tbody>
</table>
1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA’s website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative monitoring system is available on the EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and/or 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit’s monitoring system description.
Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

   (1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;
   (2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and
   (3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO2 and NOX under the Acid Rain Program.

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

<table>
<thead>
<tr>
<th>Emission Unit/Pollutant</th>
<th>Control Device</th>
<th>Applicable Emission Limitation</th>
<th>Uncontrolled PTE (tons/year)</th>
<th>Controlled PTE (tons/year)</th>
<th>CAM Applicable (Y/N)</th>
<th>Large Unit (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MB1 PM</td>
<td>ESP</td>
<td>Y</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>MB2 PM</td>
<td>ESP</td>
<td>Y</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Tanker Truck Loading for MB1 (fly ash)</td>
<td>Vacuum System</td>
<td>Y</td>
<td>&gt;100</td>
<td>&lt;100</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Tanker Truck Loading for MB2 (fly ash)</td>
<td>Vacuum System</td>
<td>Y</td>
<td>&gt;100</td>
<td>&lt;100</td>
<td>Y</td>
<td>N</td>
</tr>
</tbody>
</table>

Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for criteria pollutants (PM10, PM2.5, SO2, NOX, VOC and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy. Under the Part 70 Permit program (40 CFR 70), PM is not a regulated pollutant.

PM* For limitations under 326 IAC 6-3-2, 326 IAC 6.5, and 326 IAC 6.8, IDEM OAQ uses PM as a surrogate for the regulated air pollutant PM10. Therefore, uncontrolled PTE and controlled PTE reflect the emissions of the regulated air pollutant PM10.

Controls: BH = Baghouse, C = Cyclone, DC = Dust Collection System, RTO = Regenerative or Recuperative Thermal Oxidizer, WS = Wet Scrubber, ESP = Electrostatic Precipitator

Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are applicable to MB1, MB2, tanker truck loading for MB1, tanker truck loading for MB2, and PAC Injection for PM. A CAM plan was submitted as part of a previous permit application and the Compliance Determination and Monitoring Requirements section includes a detailed description of the CAM requirements.
State rule applicability for this source has been reviewed as follows:

**326 IAC 2-2 (Prevention of Significant Deterioration (PSD))**

The source, a power plant, is one of the 28 listed source categories and has potential to emit of at least one attainment pollutant greater than 100 tons per year. The source was initially constructed in 1977 after the promulgation of PSD on August 7, 1977. The following is the initial PSD permit issued by EPA at that time:

**Approval to Construct EPA-5-78-A-1, issued October 27, 1977**

The source was initially issued a PSD permit (Approval to Construct EPA-5-78-A-1, issued October 27, 1977) for MB1 and MB2, pursuant to PSD rule [326 IAC 2-2]. The following PSD limits were required for the two boilers:

**Condition D.1.2:**

Pursuant to Approval to Construct EPA-5-78-A-1, issued October 27, 1977, 40 CFR 52.21 (Federal Regulations for the Prevention of Significant Deterioration of Air Quality) and 326 IAC 2-2, PSD rules the Permittee shall comply with the following:

(a) Particulate Matter (PM) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 0.1 pound per million British thermal unit (MMBtu) heat input.

(b) Sulfur dioxide (SO2) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 1.2 pound per MMBtu heat input.

(c) The Permittee may not alter the height of the boilerhouse as presented in the construction application. The dispersion modeling in the application relies upon a stack height expressed as 2.5 times the height of the boilerhouse. Any change in the boilerhouse height would alter the dispersion of sulfur dioxide and particulates.

(d) The Permittee may not alter the design stack parameters identified in the construction application including, but not limited to, exit gas temperature, exit gas velocity and stack diameter (inside top). The air quality analysis relies heavily on the combination of stack parameters, control devices, the emission limitations and any change in those factors could change the results of the air quality analysis. Therefore, design changes in Units 1 and 2 must receive the prior written authorization of IDEM, OAQ.

Compliance with this condition shall satisfy the requirements of 40 CFR 52.21, 326 IAC 2-2, PSD rules.

Compliance with condition D.1.2(a) shall satisfy the PM limit under 326 IAC 6-2-1(g) - Particulate Emission Limitations for Sources of Indirect Heating.

Compliance with condition D.1.2(b) shall satisfy the requirements of 326 IAC 7-1.1-2 - Sulfur dioxide emission limitations.

Since the source went through PSD review all subsequent modifications have been evaluated against Significant Emission Rate (SER) for each of PSD pollutants.

**SSM 147-17468-00020, issued on January 10, 2005:**

This permit allowed for the replacement of the burners into low NOX burners for the Main boilers, identified as MB1 and MB2. This project was evaluated as a pollution control project (PCP) exclusion procedural requirements, pursuant to 326 IAC 2-2.3-1, which was exempted from PSD review. This source modification was appealed.
MSM 147-21930-00020, issued on November 18, 2005:
This permit allowed for the construction of material handling equipment to support the testing of various sorbents and addition of injection ports and urea handling equipment to support a short term test of urea for additional NOx removal. This project went through Actual to Projected Actual test (ATPA) that resulted in PM emissions less than Significant Emission Rate (SER) of 25 tpy and PM10 to less than 15 tpy which are minor for PSD.

SSM 147-25360-00020, issued on September 3, 2008:
This permit allowed for the construction of one (1) powdered activated carbon (PAC) injection system, identified as ACI, Two (2) pneumatic truck unloading stations and one (1) railcar unloading station for transferring activated carbon from transports to storage silos, Two (2) silos for storing activated carbon, and Four (4) capacity metering pressure tanks. This project went through Actual to Potential test (ATP) that resulted to minor for PSD for PM, PM10 and PM2.5.

SSM 147-32890-00020, issued on September 19, 2013:
This permit allowed for the construction of unit 1 Dry Sorbent Injection System, identified as (DSI-U1), Unit 2 Dry Sorbent Injection System, identified as (DSI-U2), and two (2) additional silos for storing halogenated or non-halogenated activated carbon. This project went through netting exercise for PM, PM10 and PM2.5 and netted out of PSD review for these pollutants. This source modification was appealed. To make the emission reductions claimed in the netting enforceable the following limits were required:

**Boiler MB1 and Boiler MB2**

1. The total PM emissions from Boiler MB1 and Boiler MB2 shall be limited to 2575 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

2. The total PM10 emissions from Boiler MB1 and Boiler MB2 shall be limited to 1725 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

3. The total PM2.5 emissions from Boiler MB1 and Boiler MB2 shall be limited to 746 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

**Dry Sorbent Injection System Serving Units MB1 and MB21**

1. The Dry Sorbent delivered to the site shall be limited to 142,500 tons per twelve (12) consecutive month period for both units with compliance determined at the end of each month.

2. The PM emissions from the Sorbent Silos shall be limited to 0.73 lbs per thousand tons of dry sorbent.

3. The PM10 emissions from the Sorbent Silos shall be limited to 0.48 lbs per thousand tons of dry sorbent.

4. The PM2.5 emissions from the Sorbent Silos shall be limited to 0.0028 lbs per thousand tons of dry sorbent.

5. The PM emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 33.54 lbs per thousand tons of dry sorbent.

6. The PM10 emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 6.46 lbs per thousand tons of dry sorbent.
(7) The PM2.5 emissions from the paved roads used for the Dry Sorbent delivery shall be limited to 1.54 lbs per thousand tons of dry sorbent.

Activated Carbon Injection System Serving Units MB1 and MB21

(1) The Activated Carbon delivered to the site shall be limited to 35,040 tons per twelve (12) consecutive month period for both units with compliance determined at the end of each month.

(2) The PM emissions from the Activated Carbon Silo bin vent filter shall be limited to 56.68 lbs per thousand tons of Activated Carbon.

(3) The PM10 emissions from the Activated Carbon Silo bin vent filter shall be limited to 36.99 lbs per thousand tons of Activated Carbon.

(4) The PM2.5 emissions from the Activated Carbon Silo bin vent filter shall be limited to 5.99 lbs per thousand tons of Activated Carbon.

(5) The PM emissions from the paved roads used for the Activated Carbon delivery shall be limited to 20.55 lbs per thousand tons of Activated carbon delivered.

(6) The PM10 emissions from the paved roads used for the Activated Carbon delivery shall be limited to 4.00 lbs per thousand tons of Activated carbon delivered.

(7) The PM2.5 emissions from the paved roads used for the Activated Carbon delivery shall be limited to 1.14 lbs per thousand tons of Activated carbon delivered.

The following minor PSD limits were required for the emergency generators and space heaters (there is no available information on what permit required these minor limits)

Hours of Operation Limit:
In order to make the requirements of 326 IAC 2-2 (PSD Requirements) not applicable to the diesel generators DG1, DG2, and DG3, during periods when both of the Unit 1 and Unit 2 main boilers are in service the total operating hours for all three diesel generators (DG1, DG2, and DG3) taken together shall not exceed 780 hours per twelve (12) consecutive month period. Compliance shall be demonstrated at the end of each calendar quarter.

PSD Minor Limit for SO2:
(a) In order to make the requirements of 326 IAC 2-2 (PSD Requirements) not applicable to the fuel oil-fired space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9, the emissions from the heaters shall be limited to less than forty (40) tons of sulfur dioxide (SO2) per twelve (12) consecutive month period. Compliance with this limit shall be determined at the end of each month.

(b) The sulfur content of the fuel oil fired in space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9 shall not exceed 0.5%, based on a higher heating value of 140 million Btu's per thousand gallons of fuel oil. If a fuel oil with a lower heating value is fired, the percent sulfur content must be correspondingly lower.

(c) The operation of space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9 shall not exceed 6048 hours per year, based on a twelve month sum rolled on a monthly basis.

These conditions shall limit the SO2 emissions from these seven (7) heaters to not more than 37.4 tons per year.
The following minor limits are for limited use for the auxiliary boilers required under 40 CFR Part 63.7500(c) and 63.7575, Subpart DDDDD:

**Condition 2.0:**
Beginning January 31, 2016, each auxiliary boiler shall be limited to less than 3773.06 Kilogallons of No. 2 fuel oil per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will make the boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2 limited use boilers pursuant to 40 CFR 63.7500(c).

*Note: these auxiliary commenced construction prior to the PSD rule promulgation on August 7, 1977.*

**326 IAC 2-6 (Emission Reporting)**
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of VOC/PM10 is greater than 250 tons per year, and the potential to emit of CO/NOx/SO2 is greater than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted by July 1, and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

**326 IAC 2-7-6(5) (Annual Compliance Certification)**
The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

**326 IAC 5-1 (Opacity Limitations)**
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

**326 IAC 6-4 (Fugitive Dust Emissions Limitations)**
Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

**326 IAC 6.5 (Particulate Matter Limitations Except Lake County)**
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Spencer County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

**326 IAC 6.8 (Particulate Matter Limitations for Lake County)**
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Spencer County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

**326 IAC 3-5 (Continuous Monitoring of Emissions)**
The Main Boilers, Units MB1 and MB2, are equipped with SO2, NOX, and either CO2 or O2 CEMS. The CEMS for each of these pollutants is subject to the requirements 326 IAC 3-7-5(a) where the source shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

**326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)**
Main Boilers, Unit MB1 and MB2

(a) Pursuant to 326 IAC 5-1-3(d) during boiler startups an exemption from the 20 percent opacity limit is allowed up to 40 (forty) six minute averaging periods, or until the flue gas temperature entering the electrostatic precipitator reaches 250°F, whichever occurs first.

(b) Pursuant to 326 IAC 5-1-3(d), during boiler shutdowns, an exemption from the 20 percent opacity limit is allowed for up to 10 (ten) six minute averaging periods.

Auxiliary Boilers 1 and 2

Pursuant to 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the forty percent (40%) opacity limitation established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period. [326 IAC 5-1-3(a)]

Note: 326 IAC 5-1-3(b) is not applicable to the auxiliary boilers because the opacity limit of Subpart D does not exclude times of removing ashes or blowing tubes.

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)

Main Boilers, Unit MB1 and MB2

Pursuant to 326 IAC 6-2-1(f) and (g), if any limitation established by 326 IAC 6-2 is inconsistent with applicable limitations contained in 326 IAC 12 concerning new source performance standards, or is inconsistent with a limitation contained in a facility's construction permit, then the limitations contained in the NSPS or the construction permit prevail. The NSPS Subpart D particulate limit is 0.10 lb/MMBTU, and the PSD permit established a particulate matter limit of 0.1 lb/MMBTU.

Auxiliary Boilers 1 and 2

Pursuant to 326 IAC 6-2-1(f) and (g), if any limitation established by 326 IAC 6-2 is inconsistent with applicable limitations contained in 326 IAC 12 concerning new source performance standards, then the limitations contained in the NSPS prevail. The NSPS Subpart D particulate limit is 0.10 lb/MMBTU.

326 IAC 6-3-2 (Particulate emission limitations, work practices, and control technologies)

PAC handling and storage operations

Pursuant to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PAC Handling and Storage Operations</td>
<td>30</td>
<td>40</td>
</tr>
</tbody>
</table>

The allowable particulate emission rates were calculated using the equation below:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

\[ E = 4.10 P^{0.67} \]

Where:

\[ E \text{ = rate of emission in pounds per hour and} \]

\[ P \text{ = process weight rate in tons per hour} \]

DSI handling and storage operations
Pursuant to 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSI Handling and Storage</td>
<td>50</td>
<td>44.60</td>
</tr>
</tbody>
</table>

The allowable particulate emission rates were calculated using the equation below:
Interpolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

\[ E = 55.0 P^{0.11} - 40 \]

Where: \( E \) = rate of emission in pounds per hour; and \( P \) = process weight rate in tons per hour

Coal storage and handling
Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge loading, and enclosed conveyors 5, 6, and 7</td>
<td>4000</td>
<td>96.95</td>
</tr>
<tr>
<td>Transfer Station 7E and 7W, Station 9, Station 10, Transfer Station A&amp;D, enclosed conveyors AB, BC, CB, DC, and FD, and silos at Unit 1 and 2</td>
<td>1600</td>
<td>83.82</td>
</tr>
<tr>
<td>The east system of Station 8</td>
<td>2618</td>
<td>90.71</td>
</tr>
<tr>
<td>The west system of Station 8</td>
<td>2542</td>
<td>90.30</td>
</tr>
</tbody>
</table>

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

\[ E = 55.0 P^{0.11} - 40 \]

Where: \( E \) = rate of emission in pounds per hour; and \( P \) = process weight rate in tons per hour

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the coal storage and handling system other than the coal storage piles, at a throughput rate greater than 200 tons per hour the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

Dry fly ash handling
Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:
The Summary of Process Weight Rate Limits table shows the emission units and their respective weight and emission rates:

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>The fly ash vacuum conveying system to storage silos</td>
<td>58</td>
<td>46</td>
</tr>
<tr>
<td>The ash loading to open trucks from the storage silos</td>
<td>150</td>
<td>55</td>
</tr>
<tr>
<td>Fly ash barge loading</td>
<td>52.5</td>
<td>45</td>
</tr>
<tr>
<td>Fly ash rail loading</td>
<td>50</td>
<td>45</td>
</tr>
</tbody>
</table>

The rate of emission in pounds per hour can be calculated using the equation:

\[ E = 55.0 P^{0.11} - 40 \]

where:

- \( E \) = rate of emission in pounds per hour;
- \( P \) = process weight rate in tons per hour

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash loading to tanker trucks from the storage silos at a maximum throughput rate greater than 200 tons per hour, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

### 326 IAC 7-1.1-2 (Sulfur dioxide emission limitations)

#### Main Boilers, Unit MB1 and MB2

(a) Pursuant to 326 IAC 7-1.1-2(a), the sulfur dioxide limits otherwise established by 326 IAC 7-1.1-2 are not applicable if another limit is specified in a construction permit. Therefore, the SO2 limit established in the PSD permit is the 326 IAC 7 SO2 limit, 1.2 pounds of sulfur dioxide per million BTU heat input.

(b) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of the SO2 limits in NSPS Subpart D and the PSD permit, using a thirty (30) day rolling weighted average.

#### Auxiliary Boilers 1 and 2

(a) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO2 emissions from Auxiliary Boilers 1 and 2 shall not exceed 0.5 pounds per million Btu (lbs/MMBTU).

(b) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of 0.5 pounds per MMBTU, using a calendar month average.

#### Emergency generators and space heaters

(a) Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO2 emissions from the distillate oil-fired emergency generators and space heaters shall not exceed 0.5 pounds per million Btu (lbs/MMBTU).

(b) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from the emergency generators and the space heaters do not exceed the equivalent of five-tenths (0.5) pound per million Btu heat input, using a calendar month average.

### 326 IAC 8-3-2 (Cold cleaner degreaser control equipment and operating requirements)

The degreasing operations are subject to this rule because these operations are cold cleaning operations using solvents containing VOC. The requirements of 326 IAC 8-3-2 apply to degreasing operations pursuant 326 IAC 8-3-1(c)(1)(B) because these degreasing operations were constructed after January 1,
1980 and are without remote solvent reservoirs. The Permittee shall comply with the 326 IAC 8-3-2 requirements for these degreasing operations.

326 IAC 8-3-8 (Material requirements for cold cleaner degreasers)

The degreasing operations are subject to the provisions of 326 IAC 8-3-8 pursuant to 326 IAC 8-3-1(c)(3)(B), because this source is a user of solvents for use in cold cleaning degreasers and the solvent is not intended to be used to clean electronic components. The source does not sell solvents, therefore, the requirements of 326 IAC 8-3-8(b)(1) and 326 IAC 8-3-8(c)(1) do not apply to the degreasing operations. The Permittee shall comply with the 326 IAC 8-3-8(b)(2), (c)(2) and (d) requirements for the degreasing operations.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this source are as follows:

**Testing Requirements:**

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Control Device</th>
<th>Timeframe for Testing or Date of Initial Valid Demonstration</th>
<th>Pollutant/Parameter</th>
<th>Frequency of Testing</th>
<th>Authority</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main Boilers MB1 and MB2</td>
<td>ESP</td>
<td>Two years from the last test</td>
<td>PM</td>
<td>Every second calendar year</td>
<td>40 CFR 52.21 326 IAC 2-2</td>
</tr>
<tr>
<td>Auxiliary Boilers 1 and 2</td>
<td>-</td>
<td>The greater of (a) Every two years or (b) Once every 1,000 hours of operation for that unit, or five (5) calendar years from the last test whichever occurs first</td>
<td>PM and NOx</td>
<td>The greater of (a) Every two years or (b) Once every 1,000 hours of operation for that unit, or five (5) calendar years from the last test whichever occurs first</td>
<td>Limited use only provision under 40 CFR Part 63.7500(c) and 63.7575, Subpart DDDDD</td>
</tr>
</tbody>
</table>

(b) The Compliance Monitoring Requirements applicable to this source are as follows:
## Control Parameters

<table>
<thead>
<tr>
<th>Control</th>
<th>Type of Parametric Monitoring</th>
<th>Frequency</th>
<th>Range or Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>ESP controlling main Boilers MB1 and MB2</td>
<td>Number of transformer-rectifier (T-R) sets in service and primary and secondary voltages and currents</td>
<td>Continuously recording</td>
<td>Number of sets out of service &gt; 32</td>
</tr>
<tr>
<td>SCR</td>
<td>Inlet temperature to the catalyst bed</td>
<td>Once every four (4) hours</td>
<td>Above 500°F</td>
</tr>
<tr>
<td>PAC Handling Storage silo Bin vent filters</td>
<td>Visible Emissions</td>
<td>Once per day</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Barge unloading station 1</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Barge unloading station 2</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Conveyor System baghouses</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Coal crushing Station baghouse</td>
<td>Water Pressure Drop, Visible Emissions</td>
<td>Once per week</td>
<td>0.1 to 8 inches</td>
</tr>
<tr>
<td>Coal Sampling and transfer Stations A and D baghouses</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Bunkering conveyors AB, BC, CB, DC, and FD baghouses</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Coal bunker and coal scale dust collectors</td>
<td>Visible Emissions</td>
<td>Once per week</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Ash Barge and rail loading baghouses</td>
<td>Water Pressure Drop, Visible Emissions</td>
<td>Once per day</td>
<td>0.1 to 8 inches</td>
</tr>
<tr>
<td>nozzle of each telescoping chute</td>
<td>Visible Emissions</td>
<td>Once per day</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Ash silos bin vents</td>
<td>Visible Emissions</td>
<td>Once per day</td>
<td>Normal-Abnormal</td>
</tr>
</tbody>
</table>

These monitoring conditions for each of the above controls are necessary and must operate properly to ensure compliance with 40 CFR 60, Subpart D, 326 IAC 12, 326 IAC 3-8-1, 326 IAC 2-2 and 326 IAC 2-7 (Part 70).

These monitoring conditions are necessary because the baghouses, cyclone separators, and dust collectors controlling the coal storage and handling system must operate properly to ensure compliance with the NSPS requirements, 326 IAC 5, 326 IAC 6, and 326 IAC 2-7 (Part 70).

These monitoring conditions are necessary because the ash silo bin vents, the barge and rail loading baghouse exhaust, and the nozzle of each telescoping chute must operate properly to ensure compliance with 326 IAC 5, 326 IAC 6, and 326 IAC 2-7 (Part 70).

## Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.
The following changes were made to conditions contained previously issued permits/approvals (these changes may include Title I changes):

(1) The permit has been revised to remove emission unit, and modify unit’s description for clarification. Furthermore, the permit has been revised to match current model language:

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]

(a) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB1 (Main Boiler 1), with construction commenced in 1977 and completed in 1984, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) using bulk Anhydrous Ammonia system permitted in 2015 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 1 (MB1) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U1, permitted in 2013, with a design injection capacity of 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 1 (MB1). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[This is an affected unit under 40 CFR 63, Subpart UUUUU]
[This is an affected unit under 40 CFR 60, Subpart D]

(b) One (1) pulverized coal opposed wall fired dry bottom boiler, identified as MB2 (Main Boiler 2), with construction commenced in 1977 and completed in 1989, with a design heat input capacity of 12,374 million Btu per hour, with an electrostatic precipitator (ESP) system for control of particulate matter. Low NOx burners and an overfire air (OFA) system have been installed and Selective Catalytic Reduction (SCR) permitted in 2018 using the bulk Anhydrous Ammonia system permitted in 2018 and modified in 2018 for NOx control. No. 2 fuel oil is fired during startup, shutdown, and load stabilization periods. No. 2 fuel oil may also be burned to maintain boiler temperature to ensure boiler availability on short notice, and to maintain boiler temperature required during chemical cleaning. One (1) powdered activated carbon (PAC) injection system, identified as ACI, permitted in 2008, 2010 and 2013, with a unit maximum capacity of injecting 4,000 pounds of halogenated or non-halogenated activated carbon per hour into the exhaust ductwork for Boiler 2 (MB2) from a dedicated silo(s). One (1) dry sorbent injection (DSI) system, identified as DSI-U2, permitted in 2013, with a combined maximum capacity of injecting 20,000 pounds of Sodium Bicarbonate per hour into the exhaust ductwork for Boiler 2 (MB2). Emissions from Units MB1 and MB2 are exhausted through the common stack, Stack CS012. Continuous emissions monitoring systems (CEMS) for nitrogen oxides (NOx) and for sulfur dioxide (SO2) and a continuous opacity monitoring (COM) system are located on the common stack.

[This is an affected unit under 40 CFR 63, Subpart UUUUU]
[This is an affected unit under 40 CFR 60, Subpart D]
Equations for PM, PM10 and PM2.5 PSD Netting credit have been relocated under Compliance Determination for clarification. In addition, PSD minor limit reference has been deleted from condition D.2.0 as it is an error:

D.1.2 Prevention of Significant Deterioration (PSD) - Best Available Control Technology for PM and SO2 [326 IAC 2-2]  
PSD Limits [326 IAC 2-2][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]

Pursuant to Approval to Construct EPA-5-78-A-1, issued October 27, 1977, 40 CFR 52.21 (Federal Regulations for the Prevention of Significant Deterioration of Air Quality) and 326 IAC 2-2, PSD rules the Permittee shall comply with the following:

Pursuant to Approval to Construct EPA-5-78-A-1, issued October 27, 1977, 40 CFR 52.21 (Federal Regulations for the Prevention of Significant Deterioration of Air Quality), 326 IAC 6-2-1(g), and 326 IAC 7-1.1-2(a):

(a) MB1 and MB2 (a.k.a. Units 1 and 2) must meet emission limitations of 0.1 pound of particulate matter per million BTU heat input and 1.2 pounds of sulfur dioxide per million BTU heat input. These limitations are equivalent to the New Source Performance Standards (40 CFR Part 60) for fossil-fuel fired steam generating units and are defined as best available control technology.

(b) Particulate Matter (PM) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 0.1 pound per million British thermal unit (MMBtu) heat input.

(c) Sulfur dioxide (SO2) emissions from the MB1 and MB2 (a.k.a. Units 1 and 2) shall not exceed 1.2 pound per MMBtu heat input.

(d) The Permittee may not alter the height of the boilerhouse as presented in the construction application. The dispersion modeling in the application relies upon a stack height expressed as 2.5 times the height of the boilerhouse. Any change in the boilerhouse height would alter the dispersion of sulfur dioxide and particulates.

Compliance with this condition shall satisfy the requirements of 40 CFR 52.21, 326 IAC 2-2, PSD rules.

Compliance with condition D.1.2(a) shall satisfy the PM limit under 326 IAC 6-2-1(g) - Particulate Emission Limitations for Sources of Indirect Heating.

Compliance with condition D.1.2(b) shall satisfy the requirements of 326 IAC 7-1.1-2 - Sulfur dioxide emission limitations.

(3) Testing requirements has been added for the PSD minor limits in Condition D.1.3 for clarification:

D.1.3 PSD Minor Limits [326 IAC 2-2] PM, PM10 and PM2.5 PSD Netting Credit [326 IAC 2-2]

(a) In order to render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2013 project to install DSI and ACI, the Permittee shall comply with the following:

Pursuant to SSM 147-32890-00020, issued on September 19, 2013, the following units shall be limited to render the requirements of PSD not applicable:

Boiler MB1 and Boiler MB2
1. The total PM emissions from Boiler MB1 and Boiler MB2 shall be limited to 2575 tons per twelve (12) consecutive month period with compliance determined at the end of each month. The monthly PM emissions shall be calculated using the following formula:

\[ E = (HICS_{012} \times EFPM_{012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:

- \( HICS_{012} \): Monthly Heat Input (MMBtu/month)
- \( EFPM_{012} \): a value of 0.0365 lb/MMBtu of PM for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

2. The total PM10 emissions from Boiler MB1 and Boiler MB2 shall be limited to 1725 tons per twelve (12) consecutive month period with compliance determined at the end of each month. The monthly PM emissions shall be calculated using the following formula:

\[ E = (HICS_{012} \times EFPM10_{012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:

- \( HICS_{012} \): Monthly Heat Input (MMBtu/month)
- \( EFPM10_{012} \): a value of 0.0245 lb/MMBtu of PM10 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

3. The total PM2.5 emissions from Boiler MB1 and Boiler MB2 shall be limited to 746 tons per twelve (12) consecutive month period with compliance determined at the end of each month. The monthly PM emissions shall be calculated using the following formula:

\[ E = (HICS_{012} \times EFPM25_{012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:

- \( HICS_{012} \): Monthly Heat Input (MMBtu/month)
- \( EFPM25_{012} \): a value of 0.011 lb/MMBtu of PM2.5 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.

***

### D.1.9 Compliance Determination Equation

In order to comply with Condition D.1.3 – PSD Minor Limits, emissions shall be determined from the following equations:

The monthly PM emissions shall be calculated using the following formula:

\[ E = (HICS_{012} \times EFPM_{012}) \times \frac{1}{2000} \text{(lb/ton)} \]

Where:

- \( HICS_{012} \): Monthly Heat Input (MMBtu/month)
- \( EFPM_{012} \): a value of 0.0365 lb/MMBtu of PM for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.
The monthly PM10 emissions shall be calculated using the following formula:

\[ E = (H_{ICS012} \times EF_{PM10CS012}) \times \frac{1}{2000}(\text{lb/ton}) \]

Where:

\[ H_{ICS012} = \text{Monthly Heat Input (MMBtu/month)} \]

\[ EF_{PM10CS012} = \text{a value of 0.0245 lb/MMBtu of PM10 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.} \]

The monthly PM2.5 emissions shall be calculated using the following formula:

\[ E = (H_{ICS012} \times EF_{PM25CS012}) \times \frac{1}{2000}(\text{lb/ton}) \]

Where:

\[ H_{ICS012} = \text{Monthly Heat Input (MMBtu/month)} \]

\[ EF_{PM25CS012} = \text{a value of 0.011 lb/MMBtu of PM2.5 for the common stack until a value is determined from the latest IDEM approved stack test, and that value thereafter.} \]

D.1.10  Testing Requirements  [326 IAC 2-7-6(1), (6)][326 IAC 2-1.1-11]

In order to demonstrate the compliance status with Condition D.1.2 and D.1.3, the Permittee shall perform PM stack testing of the emissions from the common stack using methods as approved by the Commissioner. This testing shall be repeated by December 31 of every second calendar year following the most recent valid compliance demonstration. Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

D.1.14  Continuous Emissions Monitoring  [326 IAC 3-5][326 IAC 12][40 CFR 60, Subpart D][326 IAC 7-2][40 CFR 52.21]

(g) Whenever a NOx CEMS is down for more than twenty-four (24) hours, the Permittee shall monitor the SCR catalyst bed inlet temperature with a continuous temperature monitoring system no less often than once per four (4) hours. Except during periods of Unit non-operation Unit start-up and Unit shutdown activities, and prior to the required operation of an SCR on either unit in accordance with Condition D.1.5(m)(o), should the catalyst bed inlet temperature fall below 500°F, the minimum temperature for SCR operation, the Permittee shall take a reasonable response action. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature reading that is below the minimum temperature is not a deviation from this permit. Failure to take reasonable response steps shall be considered a deviation from this permit.

Compliance Assurance Monitoring Requirements [40 CFR 64]

D.1.16  Transformer-Rectifier (T-R) Sets [40 CFR 64]

(b) A response shall be taken in accordance with Section C – Response to Excursions or Exceedances (Condition C.15(b)(i)) whenever the number of T-R sets out of service
is above thirty-two (32) per unit. T-R set failure resulting in more than thirty-two (32) per unit out of service is not a deviation from this permit. Failure to take a reasonable response in accordance with Condition C.14(b)(2) when more than thirty-two (32) T-R Sets are out of service shall be considered a deviation from this permit. Failure to use reasonable procedures in a response to an excursion or exceedance of the indicator range set forth above in accordance with Condition C.15(b)(4) may result in the requirement to develop a Quality Improvement Plan as set forth in Condition C.14(II)(c).

(4) Condition D.1.20(d) has been deleted as it is referencing a mistaken C Condition:

D.1.20 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity, Section C - Maintenance of Continuous Opacity Monitoring Equipment, and the particulate matter and opacity requirements in Conditions D.1.2, D.1.4, D.1.12, and D.1.16, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits in Section C - Opacity and Conditions D.1.2 and D.1.4.

(b) To document the compliance status with the SO2 requirements in Conditions D.1.2(a), D.1.13, D.1.14, and D.1.15, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the applicable SO2 limit(s) as required in Conditions D.1.2(a), D.1.13, D.1.14, and D.1.15. The Permittee shall maintain records in accordance with (3) and (4) below during SO2 CEMS malfunction or downtime.

(1) All SO2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g), 40 CFR 60.7, and 40 CFR 60.45.

(2) Actual fuel usage since last compliance determination period.

(3) All fuel sampling and analysis data collected for SO2 CEMS downtime, in accordance with Condition D.1.15.

(4) Actual fuel usage during each SO2 CEMS downtime.

(c) To document the compliance status with the NOx requirements in Condition D.1.13, the Permittee shall maintain records of all NOx and CO2 or O2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 2-2, 40 CFR 60.7, and 40 CFR 60.45. Records shall be complete and sufficient to establish compliance with the NOx limits as required in 40 CFR 60, Subpart D.

(d) Pursuant to 326 IAC 2-2 and 326 IAC 2-3, the Permittee shall maintain records as specified by Conditions C.19(c) and (d) (General Record Keeping Requirements).

(e) To document the compliance status with Condition D.1.17, the Permittee shall maintain records of the visible emission notations required by that condition. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

D.2.0 Prevention of Significant Deterioration (PSD) Minor Limits and Limited Use Boiler [326 IAC 2-2] [40 CFR Part 63.7500(c) and 63.7575, Subpart DDDDD]
Beginning January 31, 2016, each auxiliary boiler shall be limited to less than 3773.06 Kilogallons of No. 2 fuel oil per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will make the boilers, identified as Auxiliary Boiler 1 and Auxiliary Boiler 2 limited use boilers pursuant to 40 CFR 63.7500(c).

D.1.20D.1.21 Reporting Requirements

(a) A quarterly report of opacity exceedances and a quarterly summary of the information to document the compliance status with the PM and SO2 requirements of Conditions D.1.2, D.1.4, and D.1.14D.1.15 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(35).

(5) Condition D.3.1 - 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) has been updated using tables for clarification:

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(14)]

(d) A coal storage and handling system for MB1 and MB2, with installation started in 1981 and completed in 1984, consisting of the following equipment:

***

[These are affected units under 40 CFR 60, Subpart Y]

Insignificant Activities [326 IAC 2-7-1(21)]:

Coal bunker and coal scale exhausts and associated dust collector vents.

***

[These are affected units under 40 CFR 60, Subpart Y]

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:

(1) 96.95 pounds per hour from the barge loading, and enclosed conveyors 5, 6, and 7 when operating at a process weight rate of 4000 tons per hour.

(2) 83.82 pounds per hour from Transfer Station 7E and 7W, Station 9, Station 10, Transfer Station A&D, enclosed conveyors AB, BC, CB, DC, and FD, and silos at Unit 1 and 2 when operating at a process weight rate of 1600 tons per hour.

(3) 90.71 pounds per hour for the east system of Station 8 when operating at a maximum process weight rate of 2618 tons per hour.

(4) 90.30 pounds per hour for the west system of Station 8 when operating at a maximum process weight rate of 2542 tons per hour.
### Summary of Process Weight Rate Limits

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge loading, and enclosed conveyors 5, 6, and 7</td>
<td>4000</td>
<td>96.95</td>
</tr>
<tr>
<td>Transfer Station 7E and 7W, Station 9, Station 10,</td>
<td>1600</td>
<td>83.82</td>
</tr>
<tr>
<td>Transfer Station A&amp;D, enclosed conveyors AB, BC, CB, DC, and FD, and silos at Unit 1 and 2</td>
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<td></td>
</tr>
<tr>
<td>The east system of Station 8</td>
<td>2618</td>
<td>90.71</td>
</tr>
<tr>
<td>The west system of Station 8</td>
<td>2542</td>
<td>90.30</td>
</tr>
</tbody>
</table>

(6) Condition D.4.1 - 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) has been updated using tables for clarification:

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rates shall not exceed the following:

<table>
<thead>
<tr>
<th>Process / Emission Unit</th>
<th>P (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>The fly ash vacuum conveying system to storage silos</td>
<td>58</td>
<td>46</td>
</tr>
<tr>
<td>The ash loading to open trucks from the storage silos</td>
<td>150</td>
<td>55</td>
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<tr>
<td>Fly ash barge loading</td>
<td>52.5</td>
<td>45</td>
</tr>
<tr>
<td>Fly ash rail loading</td>
<td>50</td>
<td>45</td>
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</table>

(7) State Rule citation has been removed from several conditions, to match current model language:

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

D.5.1 Visible Emissions Notations [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

(g) Emergency generators as follows: Three (3) No. 2 fuel oil-fired emergency diesel generators designated as DG1, DG2, and DG3, constructed in 1983/1984, each with 25.16 MMBtu/hr heat input capacity.

[326 IAC 7][326 IAC 2]
(h) Six (6) No. 2 fuel oil-fired space heaters designated as WHU-5, WHU-6, WHU-7, WHU-8, WHU-9, and WHU-10 with heat input capacities of 4.5 MMBtu/hr, 3.0 MMBtu/hr, 2.75 MMBtu/hr, 3.5 MMBtu/hr, 4.5 MMBtu/hr, and 2.2 MMBtu/hr, respectively.

(h) Five (5) No. 2 fuel oil-fired space heaters designated as WHU-5, WHU-6, WHU-7, WHU-8, and WHU-9, with heat input capacities of 4.5 MMBtu/hr, 3.0 MMBtu/hr, 2.75 MMBtu/hr, 3.5 MMBtu/hr, and 4.5 MMBtu/hr, respectively.

(i) One (1) No. 2 fuel oil-fired space heater, identified as WHU-10, approved in 2018 for construction, with heat input capacity of 2.4 MMBtu/hr.

(8) Equation for SO2 minor PSD limit has been relocated under Compliance Determination for clarification:

D.6.3 PSD Minor Limit for SO2 [326 IAC 2-2]

In order to make the requirements of 326 IAC 2-2-1(x) and 326 IAC 2-2-1(jj) (PSD Requirements) not applicable to the fuel oil-fired space heaters WHU-1, WHU-2, WHU-5, WHU-6, WHU-7, WHU-8, WHU-9, and WHU-10, the emissions from the heaters shall be limited to less than forty (40) tons of sulfur dioxide (SO2) per twelve (12) consecutive month period with compliance determined at the end of each month. Compliance with this limit shall be determined at the end of each month, using the following equation:

\[
\text{SO}_2 \text{ Emissions} = \frac{142 \times S\% \times 22.65 \text{ MMBtu/hr} \times H \text{ (hrs/month)}}{H \text{ (MMBtu/kgal)} \times 2000 \text{ (lb/ton)}}
\]

Where:
- SO\(_2\) Emission Limit (S) = \((142 \times S\%) \text{ lbs per kilogallons}\)
- Monthly Average Sulfur Content = S (%)
- Heat Input Capacity = 22.65 MMBtu/hr
- Operating Hours = H (hrs/month)
- Monthly Average Fuel Heating Value = H (MMBtu/kgal)

Compliance with this limit, combined with the potential to emit SO2 from all other emission units at this source, shall limit the source-wide total potential to emit of SO2 to less than one-hundred (100) tons per twelve (12) consecutive month period, each and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable. Compliance with the above limit, shall limit the potential to emit of SO2 to less than 40 tons per year, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to this modification.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.6.4 Compliance Determination Equation

In order to comply with Condition D.6.3 – PSD Minor Limits, emissions shall be determined from the following equations:

\[
\text{SO}_2 \text{ Emissions} = \frac{142 \times S\% \times 22.65 \text{ MMBtu/hr} \times H \text{ (hrs/month)}}{H \text{ (MMBtu/kgal)} \times 2000 \text{ (lb/ton)}}
\]

Where:
- SO\(_2\) Emission Limit (S) = \((142 \times S\%) \text{ lbs per kilogallons}\)
- Monthly Average Sulfur Content = S (%)
- Heat Input Capacity = 22.65 MMBtu/hr
- Operating Hours = H (hrs/month)
- Monthly Average Fuel Heating Value = H (MMBtu/kgal)
**SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS**

### D.7.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

### D.7.3 Record Keeping Requirements

**Condition E.2.3 has been removed because the source fulfilled the requirements of MATS on June 16, 2016:**

### SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

#### E.2.3 ORDER of the Commissioner of the Indiana Department of Environmental Management

Pursuant to Indiana Code § 13-14-2-6 and in order to secure compliance with 40 CFR Part 63, Subpart UUUU, Indiana Michigan Power, dba American Electric Power, Rockport Plant is subject to the following ORDER:

(a) Indiana Michigan Power, dba American Electric Power shall submit a status report within fifteen (15) days of completion of the following Rockport Plant milestones indicating the actual dates of completion:

1. The dates on-site construction for the installation of the emission control equipment identified for all affected units are initiated, and
2. The dates on-site construction for the installation of the emission control equipment identified for all affected units are completed.
3. The dates by which final compliance with 40 CFR Part 63, Subpart UUUU for all affected units are achieved.


**Conclusion and Recommendation**

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on October 31, 2018.
The operation of this stationary electric utility generating station shall be subject to the conditions of the attached proposed Part 70 Operating Permit Renewal No. 147-40656-00020.

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved.

<table>
<thead>
<tr>
<th>IDEM Contact</th>
</tr>
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<tbody>
<tr>
<td>(a) If you have any questions regarding this permit, please contact Mena Mekhail, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 234-7434 or (800) 451-6027, and ask for Mena Mekhail or (317) 234-7434.</td>
</tr>
<tr>
<td>(b) A copy of the findings is available on the Internet at: <a href="http://www.in.gov/ai/appfiles/idem-caats/">http://www.in.gov/ai/appfiles/idem-caats/</a></td>
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<tr>
<td>(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: <a href="http://www.in.gov/idem/airquality/2356.htm">http://www.in.gov/idem/airquality/2356.htm</a>; and the Citizens’ Guide to IDEM on the Internet at: <a href="http://www.in.gov/idem/6900.htm">http://www.in.gov/idem/6900.htm</a>.</td>
</tr>
</tbody>
</table>
October 15, 2019

Mr. John Lagrange  
Indiana Michigan Power Co. dba AEP - Rockport  
2791 N. US Highway 231  
Rockport, IN 47635

Re: Public Notice  
Indiana Michigan Power Co. dba AEP - Rockport  
Permit Level: Title V - Renewal  
Permit Number: 147-40656-00070

Dear Mr. Lagrange:

Enclosed is a copy of your draft Title V - Renewal, Technical Support Document, emission calculations, and the Public Notice.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: [https://www.in.gov/idem/5474.htm](https://www.in.gov/idem/5474.htm)

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Spencer County Public Library, 210 N. Walnut Street, in Rockport, IN 47635-1398. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Mena Mekhail, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 4-7434 or dial (317) 234-7434.

Sincerely,

Vicki Biddle

Vicki Biddle  
Permits Branch  
Office of Air Quality

Enclosures  
PN Applicant Cover Letter 4/12/19
October 15, 2019

To:        Spencer County Public Library

From:      Jenny Acker, Branch Chief
           Permits Branch
           Office of Air Quality

Subject:   Important Information to Display Regarding a Public Notice for an Air Permit

Applicant Name:  Indiana Michigan Power Co. dba AEP - Rockport
Permit Number:   147-40656-00020

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. Please make this information readily available until you receive a copy of the final package.

If you have any questions concerning this public review process, please contact Joanne Smiddle-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library updated 4/2019
Notice of Public Comment

October 15, 2019
Indiana Michigan Power Co. dba AEP - Rockport
147-40656-00020

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has posted on IDEM’s Public Notice website at https://www.in.gov/idem/5474.htm.

The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana’s Air Permitting Program.

Please Note: If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.
AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

October 15, 2019

A 30-day public comment period has been initiated for:

Permit Number: 147-40656-00020
Applicant Name: Indiana Michigan Power Co. dba AEP - Rockport
Location: Rockport, Spencer County, Indiana

The public notice, draft permit and technical support documents can be accessed via the IDEM Air Permits Online site at: http://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.

Affected States Notification 1/9/2017
# Mail Code 61-53

<table>
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<tr>
<th>IDEM Staff</th>
<th>VBIDDLE 10/15/2019</th>
<th>Indiana Michigan Power DBA AEP Rockport 147-40656-00020 DRAFT</th>
<th>AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING</th>
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</thead>
</table>

**Name and address of Sender**

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<th>Handing Charges</th>
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<th>Due Send if COD</th>
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<th>S.H. Fee</th>
<th>Rest. Del. Fee</th>
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<tr>
<td>1</td>
<td></td>
<td>John Lagrange Indiana Michigan Power DBA AEP</td>
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<td>Ms. Francis Lueken 223 W. 10th Street, P.O.</td>
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<td>Lester Purviance 2687 East CR 600 North Grandview IN 47615 (Affected Party)</td>
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<td>Richard &amp; Betty Michel 2222 E. County Rd 700 N. Grandview IN 47615 (Affected Party)</td>
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<td>Mr. Tim Duncan 7499 N. CR 200 E. Grandview IN 47615 (Affected Party)</td>
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<td>Mr. Don Mottley Save Our Rivers 6222 Yankeetown Hwy Boonville IN 47601 (Affected Party)</td>
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<td>Ms. Kathy Tretter Dubois-Spencer Counties</td>
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<td>Mr. Steve Sisley 4410 E State Road Grandview</td>
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<td>12</td>
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<td>Spencer County Commissioners 200 Main St.,</td>
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<td>Courthouse Rockport IN 47635 (Local Official)</td>
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<td>13</td>
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<td>Spencer County Health Department Main Street</td>
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<td>Courthouse, 1st Floor, Room 1 Rockport IN 47635-1492 (Health Department)</td>
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<td>14</td>
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<td>Mr. Mark Wilson Evansville Courier &amp; Press P.O.</td>
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<td>Box 268 Evansville IN 47702-0268 (Affected Party)</td>
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<td>15</td>
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<td>David Boggs 216 Western Hills Dr Mt Vernon IN 47620 (Affected Party)</td>
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**Total number of pieces Listed by Sender**: 15

**Total number of Pieces Received at Post Office**: 15

**Postmaster, Per (Name of Receiving employee)**

The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50,000 per occurrence. The maximum indemnity payable on Express mail merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See *Domestic Mail Manual* R900, S913, and S921 for limitations of coverage on insured and COD mail. See *International Mail Manual* for limitations of coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
## Mail Code 61-53

**Name and address of Sender** | **Type of Mail:**
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Indiana Michigan Power DBA AEP Rockport 40656 (draft/final) | CERTIFICATE OF MAILING ONLY

**Name, Address, Street and Post Office Address** | **Postage** | **Handing Charges** | **Act. Value (If Registered)** | **Insured Value** | **Due Send if COD** | **R.R. Fee** | **S.D. Fee** | **S.H. Fee** | **Rest. Del. Fee** | **Remarks**
--- | --- | --- | --- | --- | --- | --- | --- | --- | --- | ---
1 | John Blair 800 Adams Ave Evansville IN 47713 (Affected Party) |  |  |  |  |  |  |  |  |  |  |
2 | Erin Whalen Earthjustice 1617 John F. Kennedy Blvd., Ste. 1130 Philadelphia PA 19103 (Affected Party) |  |  |  |  |  |  |  |  |  |  |
3 | Shannon Fisk Earthjustice 1617 John F. Kennedy Blvd., Ste. 1130 Philadelphia PA 19103 (Affected Party) |  |  |  |  |  |  |  |  |  |  |
4 | Anthony Raduazo Sierra Club Environmental Law Program 2101 Webster Street, Ste. 1250 Oakland CA 94612-3050 (Affected Party) |  |  |  |  |  |  |  |  |  |  |
5 | Jeremy & Lee Ann Hoffman 19067 N. County Road 600 E. Dale IN 47523 (Affected Party) |  |  |  |  |  |  |  |  |  |  |
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**Total number of pieces Listed by Sender** | **Total number of Pieces Received at Post Office** | **Postmaster, Per (Name of Receiving employee)** | **The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50,000 per occurrence. The maximum indemnity payable on Express mail merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See Domestic Mail Manual R900, S913, and S921 for limitations of coverage on insured and COD mail. See International Mail Manual for limitations on coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.**
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