INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
*We Protect Hoosiers and Our Environment.*
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

**NOTICE OF 30-DAY PERIOD**
**FOR PUBLIC COMMENT**

Preliminary Findings Regarding a Signficant Modification to a
Part 70 Operating Permit

for Duke Energy Indiana, LLC - Cayuga Generating Station in Vermillion County

Significant Permit Modification No.: 165-36707-00001

The Indiana Department of Environmental Management (IDEM) has received an application from Duke Energy Indiana, LLC - Cayuga Generating Station, located at SR 63, Cayuga, IN 47928, for a significant modification of its Part 70 Operating Permit issued on May 8, 2014. If approved by IDEM's Office of Air Quality (OAQ), this proposed modification would allow Duke Energy Indiana, LLC - Cayuga Generating Station to make certain changes at its existing source. Duke Energy Indiana, LLC - Cayuga Generating Station has applied to include the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters - 40 CFR Part 63 Subpart DDDDD and the Limited Use provisions of the Industrial Boiler MACT Rule into permit and the modification also include a name change of the plant.

This draft Title V 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:

Newport-Vermillion County Public Library
385 East Market Street
Newport, IN 47966

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

**How can you participate in this process?**

The date that this notice is published in a newspaper 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 SSM 165-36707-00001 in all correspondence.

**Comments should be sent to:**

Josiah Balogun
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for extension 4-5257
Or dial directly: (317) 234-5257
Fax: (317) 232-6749 attn: Josiah Balogun
E-mail: jbalogun @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 Permit Guide on the Internet at: http://www.in.gov/idem/5881.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 Josiah Balogun of my staff at the above address.

Tripurari Sinha

Tripurari P. Sinha, Ph.D., Section Chief
Permits Branch
Office of Air Quality

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**DRAFT**

Mr. Mack Sims
Duke Energy Indiana, LLC - Cayuga Generating Station
1000 East Main Street
Plainfield, IN 46168

Re: 165-36707-00001
Significant Permit Modification to
Part 70 Renewal No.: T165-33876-00001

Dear Mr. Sims:

Duke Energy Indiana, LLC - Cayuga Generating Station was issued Part 70 Operating Permit Renewal No. T165-33876-00001 on May 8, 2014 for a stationary electric utility generating station located at State Road 63, Cayuga, IN 47928. An application requesting changes to this permit was received on January 13, 2016. Pursuant to the provisions of 326 IAC 2-7-12, a Significant Permit Modification to this permit is hereby approved as described in the attached Technical Support Document.

Please find attached the entire Part 70 Operating Permit as modified. The permit references the below listed attachment(s). Since these attachments have been provided in previously issued approvals for this source, IDEM OAQ has not included a copy of these attachments with this modification:

Attachment A: Fugtitive Dust Control Plan
Attachment B: 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants
Attachment C: 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Attachment D: 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Attachment E: 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Previously issued approvals for this source containing these attachments are available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

Federal rules under Title 40 of United States Code of Federal Regulations may also be found on the U.S. Government Printing Office's Electronic Code of Federal Regulations (eCFR) website, located on the Internet at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40tab_02.tpl.

Please find attached the entire Part 70 Operating Permit as modified, including the following new attachment(s):

Attachment F: 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Previously issued approvals for this source containing these attachments are available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

**DRAFT**

Federal rules under Title 40 of United States Code of Federal Regulations may also be found on the U.S. Government Printing Office's Electronic Code of Federal Regulations (eCFR) website, located on the Internet at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40tab_02.tpl.

A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions on this matter, please contact Josiah Balogun, my staff, OAQ, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana, 46204-2251 at 317-234-5257 or 1-800-451-6027, and ask for extension 4-5257.

Sincerely,

Tripurari P. Sinha, Ph.D., Section Chief
Permits Branch
Office of Air Quality

Attachments: Modified Permit and Technical Support Document
cc: File - Vermillion County
Vermillion County Health Department
U.S. EPA, Region 5
Compliance and Enforcement Branch

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# DRAFT
# Part 70 Operating Permit Renewal

# OFFICE OF AIR QUALITY

## Duke Energy Indiana, LLC - Cayuga Generating Station
## State Road 63
## Cayuga, Indiana 47928

(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.

| Operation Permit No.: T165-33876-00001 | |
|---|---|
| Issued by: Original Signed<br>Tripurari Sinha, Ph. D., Section Chief<br>Permits Branch, Office of Air Quality | Issuance Date: May 8, 2014<br><br>Expiration Date: May 8, 2019 |

First Administrative Amendment No. 165-35161-00001, issued on December 17, 2014.
First Significant Permit Modification No. 165-34940-00001, issued on December 24, 2014.
Second Significant Permit Modification No. 165-35734-00001, issued on September 8, 2015
Second Administrative Amendment No.: 165-36292-00001

| Significant Permit Modification No.: 165-36707-00001 | |
|---|---|
| Issued by:<br><br><br>Tripurari Sinha, Ph. D., Section Chief,<br>Permits Branch<br>Office of Air Quality | Issuance Date:<br><br><br>Expiration Date: May 8, 2019 |

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E.1.1 General Provisions Relating to New Source Performance Standards (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A]
E.1.2 Standard of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]
E.1.3 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 63 [326 IAC 20-1] [40 CFR 63, Subpart A]
E.1.4 Stationary Reciprocating Internal Combustion Engines NESHAP [326 IAC 20-82] [40 CFR Part 63, Subpart ZZZZ]

**E.2. NSPS**

**New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]**
E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]
E.2.2 Standard of Performance for Nonmetallic Mineral Processing Plants Requirements [40 CFR 60, Subpart OOO] [326 IAC 12-1]

**E.3. ACID RAIN PROGRAM CONDITIONS**
E.3.1 Statutory and Regulatory Authorities
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E.3.6 Excess Emissions Requirements [40 CFR 77] [326 IAC 21]
E.3.7 Record Keeping and Reporting Requirements [326 IAC 21]
E.3.8 Submissions [326 IAC 21]
E.3.9 Severability [326 IAC 21]
E.3.10 Liability [326 IAC 21]
E.3.11 Effect on Other Authorities [326 IAC 21]

**E.4. Emission Unit Operation Conditions**

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

E.4.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [40 CFR Part 63, Subpart A]]

E.4.2 National Emission Standard for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU]

E.4.3 ORDER of the Commissioner of the Indiana Department of Environmental Management

**E.5. EMISSIONS UNIT OPERATION CONDITIONS**

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

E.5.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

E.5.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95][40 CFR Part 63, Subpart DDDDD]

**F. CLEAN AIR INTERSTATE (CAIR) NITROGEN OXIDES ANNUAL, SULFUR DIOXIDE, and NITROGEN OXIDES OZONE SEASON TRADING PROGARMS – CAIR PERMIT for CAIR UNITS Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)**

F.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

F.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

F.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

F.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

F.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

F.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

F.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Certification
Emergency Occurrence Report
Quarterly Report
Quarterly Deviation and Compliance Monitoring Report

**Attachment A - Fugitive Dust Control Plan**

**Attachment B: 40 CFR 60, Subpart OOO**
STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

**Attachment C: 40 CFR 60, Subpart IIII**
STANDARDS OF PERFORMANCE FOR STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

**Attachment D: 40 CFR 63, Subpart ZZZZ**
NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

**Attachment E: 40 CFR 63, Subpart UUUUU**
**National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units**

**Attachment F: 40 CFR Part 63, Subpart DDDDD**
National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters

## 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.5 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: | State Road 63, Cayuga, Indiana 46168 |
| General Source Phone Number: | 317-838-2108 |
| SIC Code: | 4911 |
| County Location: | Vermillion |
| Source Location Status: | Attainment for all criteria pollutants |
| Source Status: | Part 70 Operating Permit Program<br>Major Source, under PSD Rules<br>Major Source, Section 112 of the Clean Air Act<br>1 of 28 Source Categories |

### A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This source consists of a power plant and a combustion turbine plant:

(a) Duke Energy Indiana, LLC - Cayuga Generating Station (ID # 165-00001), a power plant, is located at, SR 63, Cayuga, IN 47928; and

(b) Duke Energy Indiana, LLC - Cayuga Generating Station Unit 4 combustion turbine plant (ID # 165-00086), is located at SR 63, Cayuga, IN 47928.

IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source.

IDEM, OAQ finds that the two plants are part of the same major source. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.

### A.3 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) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 1 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3A.

(d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3B.

(e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3C.

(f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3D.

(g) A dual conveyor coal processing system, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

(1) One (1) railcar unloading station, with a drop point to two (2) hoppers identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.

(2) One (1) storage area, having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.

(3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with the drop point enclosed with emissions controlled by a water spray dust suppression system as needed, and exhausting to the ambient air.

(4) One (1) enclosed hopper and two (2) reclaim feeders, with an underground drop points identified as DP-11 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.

(5) An enclosed dual conveyor system, with 6 drop points identified as DP-3 through DP-6, DP-8, and DP-13, with each drop point enclosed with emissions controlled by the enclosure. Drop points DP-3 through DP-5, DP-8, and DP-13 are

controlled as needed by a water spray dust suppression system, and DP-6 is controlled by rotoclones.

(6) An enclosed conveyor system with drop point identified as DP-9, controlled by a telescoping chute.

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

(h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) railcar/truck unloading operation, with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.

(2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(4) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(6) One (1) inactive limestone storage pile, with a maximum capacity of 45,000 tons.

(7) Two (2) reclaim hoppers, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(9) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(10) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(11) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Baghouses BH-L1 and BH-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(12) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:

(1) One (1) wet gypsum conveying system, with a maximum throughput rate of 150 tons per hour.

(2) Two (2) gypsum stock out piles. Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.

(3) One (1) emergency gypsum stockout pile, with a maximum capacity of 2,600 tons.

(4) One (1) dry gypsum transferring operation, transferring gypsum to landfills by trucks on paved roads.

(j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

(k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).

(l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A(DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).

(m) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 120 ton storage capacity, two (2) Silo Weight Feeders to regulate carbon from the silos and a system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI). The weight feeders are identified as EP-03A(ACI) and EP-04A(ACI) with spares EP-03B(ACI) and EP-04B(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, one (1) ash silo with a storage capacity of 3,500 and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper

will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to the ash silo. The ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silo is identified as emission point EP-06(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(ii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

## A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

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

(a) Degreasing operations that do not exceed one hundred forty-five (145) gallons per twelve months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(b) One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

(c) One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.

## A.5 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, T165-33876-00001, 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 submittal 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 [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

(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 T165-33876-00001 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).

Request for renewal 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

(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 V
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 $SO_2$ or $NO_X$ 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

Entire Source

### 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 Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]

Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the submitted plan. The plan is included as Attachment A.

C.7 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. 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.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

**Testing Requirements [326 IAC 2-7-6(1)]**

C.9 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, 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

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.10 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.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

(a) For new units:
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.

(b) For existing units:
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:

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

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.12 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.13 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.14 Risk Management Plan [326 IAC 2-7-5(12)] [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.15 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)

(a) CAM *Response to excursions or exceedances.*

(1) 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 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 64.8 b (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)(a)(2) 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.16 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.17 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
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement 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.18 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.19 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.20 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.

**Ambient Monitoring Requirements [326 IAC 7-3]**

C.21 Ambient Monitoring [326 IAC 7-3]

(a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

(b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]

(c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

## SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 1 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(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 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler No. 1 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This emissions limit is based on the historic Particulate Matter emission limit established under 326 IAC 6-2-3.

D.1.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in Boiler No. 1, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) reaches 250 degrees Fahrenheit, whichever occurs first.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) has dropped below 250 degrees Fahrenheit.

(3) Operation of the electrostatic precipitator is not required during these times.

(b) Firing a boiler as part of the chemical cleaning operations of the boiler and its associated tubes is considered a “startup condition” pursuant to 326 IAC 1-2-76 and subject to the exemptions as set forth in D.1.2(a).

(c) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging periods in any sixty (60) minute period. The averaging periods shall not be

permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(d) Permittee is also allowed one start up and one shut down per calendar year as follows:

(i) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of seven (7) hours (seventy (70) six (6)-minute averaging periods, consecutive or non-consecutive) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first.

(ii) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of five (5) hours (fifty (50) six (6)-minute averaging periods, consecutive or non-consecutive).

(e) Condition D.1.2 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.1.3 Sulfur Dioxide ($SO_2$) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the $SO_2$ emissions from Boiler No. 1 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day weighted rolling average. This limitation will ensure that $SO_2$ emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County $SO_2$ SIP limits.

D.1.4 Reserved

D.1.5 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.

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

D.1.6 Reserved

D.1.7 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 1 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.

(b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable $SO_2$ emission limits.

D.1.8 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(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 the induced 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.

(e) Pursuant to 326 IAC 3-5-1(c), in lieu of the requirement to monitor opacity with a COMS in accordance with 326 IAC 3-5-1 and 326 IAC 3-5-2, the Permittee shall comply with the following:

(1) Until April 16, 2016 or when the PM CEMS for monitoring PM from the scrubber stack exhaust of Boiler No. 1 is installed, certified, and operating to measure PM pursuant to this permit, the continuous opacity monitoring system for Boiler No. 1 shall be calibrated, maintained, and operated for measuring opacity, which meets the performance specification of 326 IAC 3-5-2.

(2) After the installation and certification of the PM CEMS to monitor particulate matter from the scrubbed stack exhaust of Boiler No. 1 for compliance purposes or April 16, 2016, compliance with PM limitations in Condition D.1.1 and opacity requirements will be demonstrated using a certified PM CEMS installed and certified in accordance with US EPA Performance Specification 11 (PS-11) and operated in accordance with Procedure 2 of Appendix F to 40 CFR 60. Upon PM CEMS operation as referenced above, all requirements to operate COMS at Boiler No. 1, including those set forth in Condition D.1.8(a)-(d), shall cease.

(3) Upon successful completion of the certification of the PM CEMS, the Permittee shall submit all required certification testing 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

(f) Subsections (a) through (d) of this provision D.1.8 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit on Boiler No. 1.

D.1.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.1.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

(d) Whenever a NOx or SO2 continuous emission monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring $NO_x$ or $SO_2$ emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 ($SO_2$ and $NO_x$ Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor $NO_x$ or $SO_2$ emissions pursuant to 40 CFR 75 or 326 IAC 24 ($SO_2$ and $NO_x$ Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

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

D.1.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 1 do not exceed the equivalents of the limits specified in Conditions D.1.3 (Sulfur Dioxide ($SO_2$)) using a thirty (30) day rolling weighted average.

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

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) 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.

(c) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

D.1.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Boiler No. 1 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

(a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).

(b) Compliance with the applicable particulate emission limitation in Condition D.1.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.

(c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.1.1, the Permittee shall adjust to 5% any measured carbon dioxide ($CO_2$) values that are below 5%.

(d) Whenever this PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the FGD to control particulate matter emissions shall be monitored once per day when Boiler No. 1 is in operation by measuring and recording the following:

(a) Number of recycle pumps in service; and

(b) Absorber pH.

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

D.1.12 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is 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 T-R sets.

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the percentage of T-R sets in service falls below ninety percent (90%). T-R set failure resulting in less than ninety percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

ESP Parameters

| | Unit 1 ESP |
|---|---|
| Primary Voltage | 215 – 450 V |
| Secondary Voltage | 30 – 175 kV |
| T-R Set Secondary Current | 200 – 1200 mA |

(c) Condition D.1.12 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.1.13 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the opacity exceeds twenty-five percent (25%) for

three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty-five percent (25%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(c) The requirements of (a) and (b), do not apply to Boiler No. 1 during startup and shutdown of Boiler No. 1 and do not apply when Boiler No. 1 is being controlled by the flue gas desulfurization (FGD) system.

(d) This provision D.1.13 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.1.14 $SO_2$ Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the $SO_2$ continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

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

D.1.15 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Section C - Opacity and Conditions D.1.1, D.1.2, D.1.9, D.1.12 and D.1.13, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.1.1 and D.1.2.

(1) Data and results from the most recent stack test until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6 until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(3) The results of all Method 9 visible emission readings taken during any periods of COMS downtime until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(4) PM CEMS data after April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(5) All ESP parametric monitoring readings.

(b) To document the compliance status with Conditions D.1.3, D.1.10 and D.1.14, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the $SO_2$ limits as required in

Conditions D.1.3 and D.1.10. The Permittee shall maintain records in accordance with (2) and (3) below during $SO_2$ CEM system downtime if a backup CEM is not used.

The Permittee shall maintain the following records:

(1) All $SO_2$ continuous emissions monitoring data pursuant to 326 IAC 3-5-6.

(2) All scrubber parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.1.14.

(3) Actual fuel usage during each $SO_2$ CEMS downtime.

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

D.1.16 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.1.8 shall be submitted not later than thirty (30) days following the end of each calendar quarter until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit. 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) Pursuant to 326 IAC 3-5-7, a quarterly report of $SO_2$ exceedances shall be submitted 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.

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted 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.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted 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) After April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit, Permittee shall report any PM exceedances as part of its regular deviation reports.

## SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(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.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler No. 2 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This limit is based on the historic particulate matter emissions limit established under 326 IAC 6-2-3.

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

(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in Boiler No. 2, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) reaches 250 degrees Fahrenheit, whichever occurs first.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) has dropped below 250 degrees Fahrenheit, whichever occurs first.

(3) Operation of the electrostatic precipitator is not required during these times.

(b) Firing a boiler as part of the chemical cleaning operations of the boiler and its associated tubes is considered a “startup condition” pursuant to 326 IAC 1-2-76 and subject to the exemptions as set forth in D.2.2(a).

(c) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute

averaging periods in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(d) Permittee is also allowed one start up and one shut down per calendar year as follows:

(i) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of seven (7) hours (seventy (70) six (6)-minute averaging periods, consecutive or non-consecutive) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first.

(ii) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of five (5) hours (fifty (50) six (6)-minute averaging periods, consecutive or non-consecutive).

(e) Condition D.2.2 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.2.3 Sulfur Dioxide ($SO_2$) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the $SO_2$ emissions from Boiler No. 2 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day rolling weighted average. This limitation will ensure that $SO_2$ emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County $SO_2$ SIP limits.

D.2.4 Reserved

D.2.5 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.

**Compliance Determination Requirements [326 IAC 2-7-6]**

D.2.6 Reserved

D.2.7 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 2 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.

(b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable $SO_2$ emission limits.

D.2.8 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(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 the induced 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.

(e) Pursuant to 326 IAC 3-5-1(c), in lieu of the requirement to monitor opacity with a COMS in accordance with 326 IAC 3-5-1 and 326 IAC 3-5-2, the Permittee shall comply with the following:

(1) Until April 16, 2016 or when the PM CEMS for monitoring PM from the scrubber stack exhaust of Boiler No. 2 is installed, certified, and operating to measure PM pursuant to this permit, the continuous opacity monitoring system for Boiler No. 2 shall be calibrated, maintained, and operated for measuring opacity, which meets the performance specification of 326 IAC 3-5-2.

(2) After the installation and certification of the PM CEMS to monitor particulate matter from the scrubbed stack exhaust of Boiler No. 2 for compliance purposes or April 16, 2016, compliance with PM limitations in Condition D.2.1 and opacity requirements will be demonstrated using a certified PM CEMS installed and certified in accordance with US EPA Performance Specification 11 (PS-11) and operated in accordance with Procedure 2 of Appendix F to 40 CFR 60. Upon PM CEMS operation as referenced above, all requirements to operate COMS at Boiler No. 2, including those set forth in Condition D.2.8(a)-(d), shall cease.

(3) Upon successful completion of the certification of the PM CEMS, the Permittee shall submit all required certification testing 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

(f) Subsections (a) through (d) of this provision D.2.8 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit on Boiler No. 2.

D.2.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.2

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

(d) Whenever a NOx or SO2 continuous emission monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring NOx or $SO_2$ emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 ($SO_2$ and $NO_x$ Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NOx or $SO_2$ emissions pursuant to 40 CFR 75 or 326 IAC 24 ($SO_2$ and NOx Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

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

D.2.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 2 do not exceed the equivalents of the limits specified in Conditions D.2.3 (Sulfur Dioxide ($SO_2$)) using a thirty (30) day rolling weighted average.

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

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) 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.

(c) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

D.2.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

The Permittee shall install, certify, maintain, and operate a CEMS measuring PM emissions discharged from Boiler No. 3 scrubbed stack to the atmosphere and record the output of the system as specified in paragraphs (a) through (d):

(a) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).

(b) Compliance with the applicable particulate emission limitation in Condition D.2.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.

(c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.2.1, the Permittee shall adjust to 5% any measured carbon dioxide ($CO_2$) values that are below 5%.

(d) Whenever this PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the FGD to control particulate matter emissions shall be monitored once per day when Boiler No. 2 is in operation by measuring and recording the following:

(a) Number of recycle pumps in service; and

(b) Absorber pH.

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

D.2.12 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is 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 T-R sets.

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Exceedances or Excursions whenever the percentage of T-R sets in service falls below ninety percent (90%). T-R set failure resulting in less than ninety percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

ESP Parameters

| | Unit 2 ESP |
|---|---|
| Primary Voltage | 215 – 450 V |
| Secondary Voltage | 30 – 175 kV |
| T-R Set Secondary Current | 200 – 1200 mA |

(c) Condition D.2.12 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.2.13 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the opacity exceeds twenty-five percent (25%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty-five percent (25%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(c) The requirements of (a) and (b), do not apply to Boiler No. 2 during startup and shutdown of Boiler No. 2 and do not apply when Boiler No. 2 is being controlled by the flue gas desulfurization (FGD) system.

(d) This provision D.2.13 shall apply until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

D.2.14 $SO_2$ Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the $SO_2$ continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

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

D.2.15 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Section C - Opacity and Conditions D.2.1, D.2.2, D.2.9, D.2.12 and D.2.13, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.2.1 and D.2.2.

(1) Data and results from the most recent stack test until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6 until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(3) The results of Method 9 visible emission readings taken during any periods of COMS downtime until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(4) PM CEMS data after April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(5) All ESP parametric monitoring readings.

(b) To document the compliance status with Conditions D.2.3, D.2.10 and D.2.14, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the $SO_2$ limits as required in Conditions D.2.3 and D.2.10. The Permittee shall maintain records in accordance with (2) and (3) below during $SO_2$ CEM system downtime if a backup CEM is not used.

(1) All $SO_2$ continuous emissions monitoring data pursuant to 326 IAC 3-5-6.

(2) All scrubber parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.14.

(3) Actual fuel usage during each $SO_2$ CEMS downtime.

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

D.2.16 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of opacity exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter until April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit. 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) Pursuant to 326 IAC 3-5-7, a quarterly report of $SO_2$ exceedances shall be submitted 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.

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted 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.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted 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) After April 16, 2016 or when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit, Permittee shall report any PM exceedances as part of its regular deviation reports.

## SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3A.

(d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3B.

(e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3C.

(f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3D.

(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.3.1 Sulfur Dioxide ($SO_2$) [326 IAC 7-1.1-1]

Pursuant to 326 IAC 7-1.1 ($SO_2$ Emissions Limitations), the $SO_2$ emissions from each generator shall not exceed five-tenths (0.5) pound per million Btu heat input.

D.3.2 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.

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

D.3.3 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

(a) 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.

(b) 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 delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

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

(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.

(C) As an alternate to (A) and (B) above, samples may be collected prior to combustion (as burned) on each day fuel is combusted.

(c) 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)]

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

D.3.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission (VE) notations of the generators' stack exhausts shall be performed once per day during normal daylight operations. 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, 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 the generators.

(e) If abnormal emissions are observed at any generators' exhaust, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 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.

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

D.3.5 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Condition D.3.1, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications, or the records of fuel sampling and analysis, represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document the compliance status with Condition D.3.4, the Permittee shall maintain records of visible emission notations of the generators' stack exhausts. 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 unit did not operate that day).

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

## SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(g) A dual conveyor coal processing system, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

(1) One (1) railcar unloading station, with a drop point to two (2) hoppers identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.

(2) One (1) storage area, having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.

(3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with the drop point enclosed with emissions controlled by a water spray dust suppression system as needed, and exhausting to the ambient air.

(4) One (1) enclosed hopper and two (2) reclaim feeders, with an underground drop points identified as DP-11 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.

(5) An enclosed dual conveyor system, with 6 drop points identified as DP-3 through DP-6, DP-8, and DP-13, with each drop point enclosed with emissions controlled by the enclosure. Drop points DP-3 through DP-5, DP-8, and DP-13 are controlled as needed by a water spray dust suppression system, and DP-6 is controlled by rotoclones.

(6) An enclosed conveyor system with drop point identified as DP-9, controlled by a telescoping chute.

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

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

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points, coal scale exhausts, and coal bunkers shall not exceed 86.19 pounds per hour when operating at a process weight rate of 1900 tons per hour. This is determined by the following equation:

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 = 950 (process weight rate in tons per hour)

When the process weight exceeds two hundred (200) tons/hour, the maximum allowable emission may exceed 86.19 pounds per hour, provided the concentration of particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

D.4.2 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.

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

D.4.3 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 Section C - Opacity and Condition D.4.1, the dust collectors shall be in operation at all times the coal bunker and coal scales are in operation.

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

D.4.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts shall be performed once per week during normal daylight operations when transferring coal. 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, eighty percent (80%) of the time the process is in operation.

(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 from the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts, 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 violation of 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.

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

D.4.5 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Section C - Opacity, Section C -Fugitive Dust Emissions, and Condition D.4.4, the Permittee shall maintain records of visible emission notations of the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the unit 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.5 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) railcar/truck unloading operation, with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.

(2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(4) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(6) One (1) inactive limestone storage pile, with a maximum capacity of 45,000 tons.

(7) Two (2) reclaim hoppers, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(9) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(10) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(11) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Baghouses BH-L1 and BH-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(12) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:

(1) One (1) wet gypsum conveying system, with a maximum throughput rate of 150 tons per hour.

(2) Two (2) gypsum stock out piles. Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.

(3) One (1) emergency gypsum stockout pile, with a maximum capacity of 2,600 tons.

(4) One (1) dry gypsum transferring operation, transferring gypsum to landfills by trucks on paved roads.

(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.5.1 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (PSD) not applicable, the Permittee shall comply with the following:

(a) The total limestone received shall not exceed 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The PM/$PM_{10}$ emissions from the lime handling operations shall not exceed the emission limits listed in the table below:

| Emission Point | Unit Description | PM Emission Limit (lbs/ton) | $PM_{10}$ Emission Limit (lbs/ton) |
|---|---|---|---|
| EP-L1 | Railcar/Truck Unloading | 2.50E-05 | 2.50E-05 |
| EP-L2 | Hoppers | 7.50E-04 | 2.75E-04 |
| EP-L2 | Belt Feeders | 7.50E-04 | 2.75E-04 |
| EP-L3 | Conveyor LH-1 | 1.50E-03 | 5.50E-04 |
| EP-L4 | Reclaim Hoppers | 7.50E-04 | 2.75E-04 |
| EP-L4 | Belt Feeders | 7.50E-04 | 2.75E-04 |
| EP-L18abc | Conveyor LH-2 | 7.50E-04 | 2.75E-04 |
| EP-L18abc | Conveyor LH-3 | 7.50E-04 | 2.75E-04 |
| EP-L16 | Day Bin Unit 1 | 3.00E-03 | 1.10E-03 |
| EP-L17 | Day Bin Unit 2 | 3.00E-03 | 1.10E-03 |

(c) The emissions from the following units of the limestone handling system shall be controlled by the control method specified in the table below:

| Emission Point | Unit | Control Method |
|---|---|---|
| EP-L1 | Railcar/Truck Unloading Operation | Fog Dust Suppression |
| EP-L2 | Hoppers<br>Belt Feeders LHBF-1 and LHBF-2 | Fog Dust Suppression |
| EP-L3 | Conveyor LH-1 | Telescoping Chute |
| EP-L4 | Reclaim Hoppers<br>Belt Feeders LHBF-3 and LHBF-4 | Fog Dust Suppression |
| EP-L18a, b, c | Conveyors LH-2 and LH-3 | Fog Dust Suppression |

(d) The total gypsum processed shall not exceed 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(e) The PM/$PM_{10}$ emissions from the gypsum conveying system shall not exceed the emission limits listed in the table below:

| Unit Description | PM Emission Limit (lbs/ton) | $PM_{10}$ Emission Limit (lbs/ton) |
|---|---|---|
| Gypsum Conveying System | 0.00014 | 0.000046 |

(f) The limestone and gypsum stockpiles shall be controlled by wet suppression. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with 326 IAC 2-2.

Compliance with these limits will limit the potential to emit of PM and $PM_{10}$ from the limestone handling and the gypsum handling systems to less than 25 tons per year for PM and less than 15 tons per year for $PM_{10}$, and render the requirements of 326 IAC 2-2 (PSD) not applicable to these units.

D.5.2 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), particulate emissions from the following emission units at the limestone handling and storage system, and the gypsum conveying system shall not exceed the emission limits listed in the table below while operating at the maximum throughput rate:

| Unit Description | Max. Throughput Rate (tons/hr) | Particulate Emission Limit (lbs/hr) |
|---|---|---|
| Railcar/Truck Unloading Operation | 1,000 | 77.6 |
| Each of the Hoppers | 500 | 69.0 |
| Each of the Belt Feeders (LHBF-1 and LHBF-2) | 500 | 69.0 |
| Each of the Reclaim Hoppers | 200 | 58.5 |
| Each of the Belt Feeders (LHBF-3 and LHBF-4) | 200 | 58.5 |
| Gypsum Conveying System | 150 | 55.4 |

The limitations for these facilities were calculated using the following equations.

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

(b) Pursuant to 326 IAC 6-3-2(e)(3), when the process weight exceeds 200 tons per hour, the maximum allowable emission may exceed that shown in this table, provided the concentration of particulate matter in the gas discharged to the atmosphere is less than 0.10 pounds per 1,000 pounds of gases.

D.5.3 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.

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

D.5.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the stack exhausts from the conveyors (EP-L3, EP-L18a through c) of the limestone handling and storage system shall be performed once per week during normal daylight operations when transferring limestone. 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, 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 of 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.

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

D.5.5 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Condition D.5.1(a), the Permittee shall maintain monthly records of the weight of limestone processed.

(b) To document the compliance status with Condition D.5.1(d), the Permittee shall maintain monthly records of the weight of gypsum processed.

(c) To document the compliance status with Condition D.5.4 Visible Emissions Notations, the Permittee shall maintain records of the the weekly visible emission notations of the transfer points, railcar unloading stations and all response steps taken and the outcome for each. The Permittee shall include in its records 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) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.5.6 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

A quarterly summary of the information to document compliance with Conditions D.5.1(a) and D.5.1(d) 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.6 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

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

In order to render auxiliary boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c), the Permittee shall comply with the following:

The fuel usage of the auxiliary boiler, identified as Aux shall not exceed 455.2697 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 boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c).

D.6.1 Sulfur Dioxide ($SO_2$) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 ($SO_2$ Emissions Limitations) the $SO_2$ emissions from the Auxiliary Boiler shall not exceed five tenths (0.5) pounds per MMBtu heat input when combusting distillate oil.

D.6.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c), the PM emissions from the Auxiliary Boiler stack shall not exceed 0.233 pound per million Btu heat input (lbs/MMBtu).

D.6.3 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.

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

D.6.4 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-6]

Compliance shall be determined utilizing one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per million Btu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification; or

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the Auxiliary Boiler, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

(c) As an alternate to (A) and (B) above, samples may be collected prior to combustion (as burned) on each day fuel is combusted.

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

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

D.6.5 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the Auxiliary Boiler stack exhaust (Aux-1) shall be performed once per day during normal daylight operations. 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, 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.

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

D.6.6 Record Keeping Requirement [326 IAC 2-7-5(3)][326 IAC 2-7-19]

(a) To document the compliance status with Conditions D.6.1, the Permittee shall maintain records in accordance with (1) through (3) below.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel usage of each fuel used since last compliance determination period;

(3) If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(i) Fuel supplier certifications.

(ii) The name of the fuel supplier; and

(iii) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

(b) To document the compliance status with Condition D.6.5, the Permittee shall maintain records of visible emission notations of the boiler stack (Aux-1) exhaust. The Permittee shall include in its records 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).

(c) To document the compliance status with Condition D.6.0, the Permittee shall maintain records of fuel usage for the days the boiler, identified as Aux is operating.

(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 [326 IAC 2-7-5(3)][326 IAC 2-7-19]

A quarterly report of the information to document the compliance status with Condition D.6.0 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.

## SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).

(l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A(DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).

(m) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 120 ton storage capacity, two (2) Silo Weight Feeders to regulate carbon from the silos and a system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI). The weight feeders are identified as EP-03A(ACI) and EP-04A(ACI) with spares EP-03B(ACI) and EP-04B(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, one (1) ash silo with a storage capacity of 3,500 and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to the ash silo. The ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silo is identified as emission point EP-06(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(ii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

(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.7.1 Prevention of Significant Deterioaration (PSD) Minor Limits [326 IAC 2-2]

The Permittee shall comply with the following:

(a) Fly ash unloaded from the fly ash silo shall either be unloaded wet into open trucks with the ash having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.

(b) The PM, $PM_{10}$ and $PM_{2.5}$ emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as need to prevent dusting.

(c) The PM, $PM_{10}$ and $PM_{2.5}$ emissions from the limestone, dry sorbent, activated carbon, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

| Emission Point | Unit Description | PM Emission Limit (lbs/hr) | PM10 Emission Limit (lbs/hr) | PM2.5 Emission Limit (lbs/hr) |
|---|---|---|---|---|
| EP-01(LS) | Limestone Silo | 0.094 | 0.094 | 0.094 |
| EP-02(LS) | Limestone Surge Bin | 0.097 | 0.097 | 0.097 |
| EP-01(DSI) | Unit 1DSI Silo #1 | 0.043 | 0.043 | 0.043 |
| EP-03(DSI) | Unit 2 DSI Silo #1 | 0.043 | 0.043 | 0.043 |
| EP-05A(DSI) | Sorbent Silo Weight Feeders | 0.0086 | 0.0086 | 0.0086 |
| EP-05B(DSI) | Sorbent Silo Weight Feeders | | | |
| EP-06A(DSI) | Sorbent Silo Weight Feeders | 0.0086 | 0.0086 | 0.0086 |
| EP-06B(DSI) | Sorbent Silo Weight Feeders | | | |
| EP-01(ACI) | Unit 1 ACI Silo | 0.043 | 0.043 | 0.043 |
| EP-02(ACI) | Unit 2 ACI Silo | 0.043 | 0.043 | 0.043 |
| EP-03A(ACI) | Carbon Silo Weight Feeders | 0.0086 | 0.0086 | 0.0086 |
| EP-04A(ACI) | Carbon Silo Weight Feeders | 0.0086 | 0.0086 | 0.0086 |
| EP-01(DFA) | Baghouse Separator 1A Exhauster | 0.21 | 0.21 | 0.21 |
| EP-02(DFA) | Baghouse Separator 1B Exhauster | 0.21 | 0.21 | 0.21 |
| EP-03(DFA) | Baghouse Separator 2A Exhauster | 0.21 | 0.21 | 0.21 |

| Emission Point | Unit Description | PM Emission Limit (lbs/hr) | PM10 Emission Limit (lbs/hr) | PM2.5 Emission Limit (lbs/hr) |
|---|---|---|---|---|
| EP-04(DFA) | Baghouse Separator 2B Exhauster | 0.21 | 0.21 | 0.21 |
| EP-05(DFA) | Spare Baghouse Separator Exhauster | 0.21 | 0.21 | 0.21 |
| EP-06(DFA) | Ash Silo #1 | 0.21 | 0.21 | 0.21 |
| EP-02(FIX) | Lime Silo | 0.103 | 0.103 | 0.103 |

Compliance with these limits in conjunction with the potential fugitive emissions from vehicular traffic, will ensure that the PM emissions are less than 25 tons per year, $PM_{10}$ emissions are less than 15 tons per year and $PM_{2.5}$ emissions are less than 10 tons per year, and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2013 modification.

D.7.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the (2) Sorbent Silos, (1) Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$E = 4.1 P^{0.67}$

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, the particulate matter (PM) from the (1) Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$E = 4.1 P^{0.67}$

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

(c) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following 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

(d) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from **the** ash silo shall not exceed 47.8 pounds per hour when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following 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

D.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.

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

D.7.4 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with the particulate matter emissions limits specified in conditions D.7.1(c) and D.7.2 the filter separators, and silo bin vent filters shall in operation and controlling emissions whenever the equipment is in operation and venting to the control device.

(b) In order to ensure compliance with Condition D.7.1(a), the Permittee shall wet the ash when unloading into open trucks. If the weather conditions preclude the use of water, the Permittee shall use additional wet suppression. The Permittee shall perform moisture content analysis, weekly on the ash to ensure it has a moisture content of not less than 15%. Additional wetting of the ash should be applied if visible emissions are observed during the loading process.

D.7.5 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

Within 180 days after the initial startup of the pneumatic fly ash transfer system, In order to determine compliance with Condition D.7.1(c), the Permittee shall perform PM, $PM_{10}$ and $PM_{2.5}$ testing two (2) of the five (5) separator/exhausters, identified as emissions point EP-01 (DFA), EP-02 (DFA), EP-03 (DFA), EP-04 (DFA) and EP-05 (DFA), using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. 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.

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

D.7.6 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) Visible emission notations of the stack exhausts for the (1) Limestone Silo (1) Limestone Surge Bin, (2) ACI Silos, (2) DSI Silos, and (1) Lime Silo shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the stack for the (4) baghouse separator exhausters, and one (1) ash silo shall be performed once per day during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the fixated material storage pile shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(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, not counting startup or shut down time.

(f) 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.

(g) 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.

(h) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 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.7.7 Parametric Monitoring [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)][40 CFR 64]

The Permittee shall record the pressure drop across each baghouse filter separator used in conjunction with the dry ash handling system, at least once per day when the dry ash handling system is exhausting to the atmosphere. When, for any one reading, the pressure drop across the baghouse is outside of the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered deviation from the permit.

The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated as specified by the manufacturer.

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

D.7.8 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) To document the compliance status with Condition D.7.6(a) - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the stack exhausts for the (1) Limestone Silo, (1) Limestone Surge Bin, (2) ACI Silos, (2) DSI Silos and (1) Lime Silo. The Permittee shall include in its weekly 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 week).

(b) To document the compliance status with Condition D.7.6(b) - Visible Emission Notation, the Permittee shall maintain daily records of the visible emission notations of the stack exhaust for (5) Baghouse Filter Separators Exhausters, and Ash Silos when in operation. 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).

(c) To document the compliance status with Condition D.7.6(c) - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the fixated material storage pile when in operation. The Permittee shall include in its weekly 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 week).

(d) To document the compliance status with Condition D.7.7 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse filter separator. The Permittee shall include in its daily record when a pressure drop reading is

not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

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

## SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(a) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(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.8.1 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.8.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on or after January 1, 2015, 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.8.3 Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

(a) Pursuant to 326 IAC 8-3-8(c)(2), on or after January 1, 2015, 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

**SECTION E.1 NSPS AND NESHAP**

**Emissions Unit Description:**

(b) One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

(c) One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.

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

E.1.1 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 IIII.

(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.1.2 Standard of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12] [40 CFR 60, Subpart IIII]

Pursuant to 40 CFR 60 Subpart IIII, the Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII (included as Attachment C to this permit), which are incorporated by reference as 326 IAC 12, for ENG-1 and ENG-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.1.3 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 63 [326 IAC 20-1] [40 CFR 63, Subpart A]

(a) Pursuant to 40 CFR 63.6665, 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 ENG-2, as specified in 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR Part 63, Subpart ZZZZ.

(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.1.4 Stationary Reciprocating Internal Combustion Engines NESHAP [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]

Pursuant to 40 CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart ZZZZ, which are incorporated by reference as 326 IAC 20-82 (included as Attachment D to this permit), for the above listed emissions units, as specified as follows.

(a) ENG-1 is subject to the following portions of Subpart ZZZZ.

(1) 40 CFR 63.6585
(2) 40 CFR 63.6590(a)(2)(ii), (c)(6)
(3) 40 CFR 63.6595(a)(4)
(4) 40 CFR 63.6665
(5) 40 CFR 63.6670
(6) 40 CFR 63.6675

(b) ENG-2 is subject to the following portions of Subpart ZZZZ.

(1) 40 CFR 63.6585
(2) 40 CFR 63.6590(a)(2)(i), (b)(1)(i)
(3) 40 CFR 63.6595(a)(3), (c)
(4) 40 CFR 63.6600(c)
(5) 40 CFR 63.6605(b)
(6) 40 CFR 63.6640(f)
(7) 40 CFR 63.6645(f)
(8) 40 CFR 63.6665
(9) 40 CFR 63.6670
(10) 40 CFR 63.6675

**SECTION E.2 NSPS**

**Emissions Unit Description:**

(i) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(2) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(3) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(4) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission points EP-L18a and EP-L18c. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour, and exhausting to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(6) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(7) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of one (1) Sorbent Storage Silo with a storage capacity of 120 tons, three (3) Silo Weight Feeders to regulate sorbent from the silos and a system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo and the weight feeders. The two (2) Sorbent Silos are identified as emission points EP-01(DSI), and EP-03(DSI). The weight feeders are identified as EP-05A (DSI), EP-05B(DSI), EP-06A(DSI) and EP-06B(DSI) with spares EP-05C(DSI) and EP-06C(DSI).

(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 2-7-5(1)]**

E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 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 ball mills, conveyors, and storage bins of the limestone handling and storage system, except as otherwise specified in 40 CFR Part 60, Subpart OOO.

(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.2.2 Standard of Performance for Nonmetallic Mineral Processing Plants Requirements [40 CFR Part 60, Subpart OOO] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of Standard of Performance for Nonmetallic Mineral Processing Plants (included as Attachment B to this permit), which are incorporated by reference as 326 IAC 12, for the ball mills, conveyors, and storage bins of the limestone handling and storage system as specified as follows:

(1) 40 CFR 60.670
(2) 40 CFR 60.671
(3) 40 CFR 60.672
(4) 40 CFR 60.673
(5) 40 CFR 60.674
(6) 40 CFR 60.675
(7) 40 CFR 60.676
(8) Table 1 to Subpart OOO
(9) Table 2 to Subpart OOO
(10) Table 3 to Subpart OOO

## SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NOX), sulfur dioxide (SO2), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 1 was configured with a low NOX burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

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

### E.3.1. Statutory and Regulatory Authorities

In accordance with IC 13-17-3-4 and IC 13-17-3-11 as well as Titles IV and V of the Clean Air Act, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) issues this permit pursuant to 326 IAC 2 and 326 IAC 21 (incorporates by reference 40 Code of Federal Regulations (CFR) 72 through 78).

### E.3.2. Standard Permit Requirements [326 IAC 21]

(a) The designated representative has submitted a complete acid rain permit application in accordance with 40 CFR 72.30.

(b) The Permittee shall operate Units 1 and 2 in compliance with this permit.

### E.3.3. Monitoring Requirements [326 IAC 21]

(a) The Permittee and, to the extent applicable, the designated representative of Units 1 and 2 shall comply with the monitoring requirements as provided in 40 CFR 75 and 76.

(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 76 shall be used to determine compliance by Units 1 and 2 with the acid rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(c) The requirements of 40 CFR 75 and 76 shall not affect the responsibility of the Permittee to monitor emissions of other pollutants or other emissions characteristics at Units 1 and 2 under other applicable requirements of the Clean Air Act and other provisions of the operating permit for the source.

E.3.4. Sulfur Dioxide Requirements [326 IAC 21]

(a) The Permittee shall:

(1) Hold allowances, as of the allowance transfer deadline (as defined in 40 CFR 72.2), in the compliance subaccount of Units 1 and 2, after deductions under 40 CFR 73.34(c), not less than the total annual emissions of sulfur dioxide for the previous calendar year from Units 1 and 2; and,

(2) Comply with the applicable acid rain emissions limitations for sulfur dioxide.

(b) Each ton of sulfur dioxide emitted in excess of the acid rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Clean Air Act.

(c) Units 1 and 2 shall be subject to the requirements under paragraph 4(a) of the sulfur dioxide requirements as follows:

(1) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or,

(2) Starting on the latter of January 1, 2000, or the deadline for monitor certification under 40 CFR 75, an affected unit under 40 CFR 72.6(a)(3).

(d) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(e) An allowance shall not be deducted in order to comply with the requirements under paragraph 4(a) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(f) An allowance allocated by the U.S. EPA under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the acid rain permit application, the acid rain permit, the acid rain portion of an operating permit, or the written exemption under 40 CFR 72.7 and 72.8 and 326 IAC 21, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(g) An allowance allocated by U.S. EPA under the Acid Rain Program does not constitute a property right.

(h) No permit revision may be required for increases in emissions that are authorized by allowances acquired pursuant to the Acid Rain Program, provided that the increases do not require a permit revision under any other applicable requirement. [326 IAC 2-7-5(4)(A)]

(i) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not, however, use allowances as a defense to noncompliance with any applicable requirement other than the requirements of the Acid Rain Program. [326 IAC 2-7-5(4)(B)]

E.3.5. Nitrogen Oxides Requirements [326 IAC 21]

The Permittee shall comply with the applicable acid rain emissions limitation of nitrogen oxides (NOx) for Units 1 and 2.

NOx Emission Averaging Plan for Unit 1:

(1) Pursuant to 40 CFR 76.11, the Indiana Department of Environmental Management, Office of Air Quality approves a NOx emission averaging plan for Unit 1, effective from calendar year 2005 through 2007. Under the plan the NOx emissions from Unit 1 shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.34 lb/MMBtu. In addition, Unit 1 shall not have an annual heat input less than 36,100,000 MMBtu. Unit 1 shall revert to the $NO_X$ Btu-weighted annual average emission rate in compliance with 40 CFR 76.5, 76.6 or 76.7 on January 1, 2008. If Unit 1 is in compliance with its applicable emission limitation for each year of the plan, then Unit 1 shall not be subject to the applicable emission limitation, under 40 CFR 76.5(a)(1), of 0.45 lb/MMBtu until January 1, 2008.

(2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 1 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.

NOx Emission Averaging Plan for Unit 2:

(1) Pursuant to 40 CFR 76.11, the Indiana Department of Environmental Management, Office of Air Quality approves a NOx emission averaging plan for Unit 2, effective from calendar year 2005 through 2007. Under the plan the NOx emissions from Unit 2 shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.35 lb/MMBtu. In addition, Unit 2 shall not have an annual heat input less than 34,600,000 MMBtu. Unit 2 shall revert to the $NO_X$ Btu-weighted annual average emission rate in compliance with 40 CFR 76.5, 76.6 or 76.7 on January 1, 2008. If Unit 2 is in compliance with its applicable emission limitation for each year of the plan, then Unit 2 shall not be subject to the applicable emission limitation, under 40 CFR 76.5(a)(1), of 0.45 lb/MMBtu until January 1, 2008.

(2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 2 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Ohio Environmental Protection Agency, Division of Air Pollution Control; and the Kentucky

Department of Environmental Protection, Division of Air Quality have also approved this averaging plan.

In addition to the described NOx compliance plan, Units 1 and 2 shall comply with all other applicable requirements of 40 CFR 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.

Pursuant to 40 CFR 76, Acid Rain Nitrogen Oxides Emission Reduction Program, the natural gas fired turbine, Unit 4 is not subject to the nitrogen oxide limitations set out in 40 CFR 76.

E.3.6 Excess Emissions Requirements [40 CFR 77] [326 IAC 21]

(a) If Unit 1 or 2 has excess emissions of sulfur dioxide in any calendar year, the designated representative shall submit a proposed offset plan to U.S. EPA and IDEM, OAQ as required under 40 CFR 77 and 326 IAC 21.

(b) The designated representative shall submit required information 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

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code (6204N)
Washington, DC 20460

(c) If Unit 1 or 2 has excess emissions, as defined in 40 CFR 72.2, in any calendar year the Permittee shall:

(1) Pay to U.S. EPA without demand the penalty required, and pay to U.S. EPA upon demand the interest on that penalty, as required by 40 CFR 77 and 326 IAC 21; and,

(2) Comply with the terms of an approved sulfur dioxide offset plan, as required by 40 CFR 77 and 326 IAC 21.

E.3.7. Record Keeping and Reporting Requirements [326 IAC 21]

(a) Unless otherwise provided, the Permittee shall keep on site each of the following documents for a period of 5 years, as required by 40 CFR 72.9(f), from the date the document is created. This period may be extended for cause, at any time prior to the end of the 5 years, in writing by U.S. EPA or IDEM, OAQ:

(1) The certificate of representation for the designated representative of Units 1 and 2 and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

(2) All emissions monitoring information collected in accordance with 40 CFR 75 shall be retained on site for 3 years;

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

(4) Copies of all documents used to complete an acid rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(b) The designated representative of Units 1 and 2 shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 72.90, Subpart I, 40 CFR 75, and 326 IAC 21. The required information is to be submitted to the appropriate authority(ies) as specified in 40 CFR 72.90, Subpart I, and 40 CFR 75.

E.3.8. Submissions [326 IAC 21]

(a) The designated representative of Units 1 and 2 shall submit a certificate of representation, and any superseding certificate of representation, to U.S. EPA and IDEM, OAQ in accordance with 40 CFR 72 and 326 IAC 21.

(b) The designated representative shall submit required information 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

and

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code (6204N)
Washington, DC 20460

(c) Each such submission under the Acid Rain Program shall be submitted, signed and certified by the designated representative for all sources on behalf of which the submission is made.

(d) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature, the following statements which shall be included verbatim in the submission:

(1) “I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made.”; and,

(2) “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(e) The designated representative of Units 1 and 2 shall notify the Permittee:

(1) By the date of submission, of any Acid Rain Program submissions by the designated representative;

(2) Within 10 business days of receipt of any written determination by U.S. EPA or IDEM, OAQ; and,

(3) Provided that the submission or determination covers Unit 1 and 2.

(f) The designated representative of Units 1 and 2 shall provide the Permittee a copy of any submission or determination under paragraph 8(e), unless the Permittee expressly waives the right to receive a copy.

E.3.9. Severability [326 IAC 21]

Invalidation of the acid rain portion of an operating permit does not affect the continuing validity of the rest of the operating permit, nor shall invalidation of any other portion of the operating permit affect the continuing validity of the acid rain portion of the permit. [40 CFR 72.72(b), 326 IAC 21, and 326 IAC 2-7-5(5)]

E.3.10. Liability [326 IAC 21]

(a) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, an acid rain permit, an acid rain portion of an operation permit, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement by U.S. EPA pursuant to Section 113(c) of the Clean Air Act and shall be subject to enforcement by IDEM pursuant to 326 IAC 21 and IC 13-30-3.

(b) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Clean Air Act, 18 U.S.C. 1001 and IDEM pursuant to 326 IAC 21 and IC 13-30-6-2.

(c) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(d) Units 1 and 2 shall meet the requirements of the Acid Rain Program.

(e) Any provision of the Acid Rain Program that applies to Unit 1 or 2, including a provision applicable to the designated representative of Unit 1 or 2 shall also apply to the Permittee.

(f) Any provision of the Acid Rain Program that applies to Unit 1 or 2 4, including a provision applicable to the designated representative, shall also apply to the Permittee. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NOx averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR 75, including 40 CFR 75.16, 75.17, and 75.18, the Permittee and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(g) Each violation of a provision of 40 CFR 72, 73, 75, 76, 77, and 78 by Unit 1 or 2, or by the Permittee or designated representative shall be a separate violation of the Clean Air Act.

E.3.11. Effect on Other Authorities [326 IAC 21]

No provision of the Acid Rain Program, an acid rain permit application, an acid rain permit, an acid rain portion of an operation permit, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(a) Except as expressly provided in Title IV of the Clean Air Act (42 USC 7651 to 7651(o)), exempting or excluding the Permittee and, to the extent applicable, the designated representative of Unit 1 or 2 from compliance with any other provision of the Clean Air Act, including the provisions of Title I of the Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(b) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Clean Air Act;

(c) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(d) Modifying the Federal Power Act (16 USC 791(a) et seq.) or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(e) Interfering with or impairing any program for competitive bidding for power supply in a state in which such a program is established.

## SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 1 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(The information describing the process contained in this emissions unit 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)]**

E.4.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.10040, the Permittee shall comply with the provisions of 40 CFR Part 63 Subpart A – General Provisions, for the above listed units, as specified in 40 CFR 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

And

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch – Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

E.4.2 National Emission Standard for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR Part 63, Subpart UUUUU]

Pursuant to 40 CFR Part 63, Subpart UUUUU, the Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units (included as Attachment E to this permit), for the two (2) boilers (Boiler 1 and Boiler 2).

E.4.3 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 UUUUU, Duke Energy Indiana, Cayuga Generating Station is subject to following ORDER:

1. Duke Energy Indiana shall submit a status report within fifteen (15) days of completion of the following milestones indicating the actual dates of completion:

    a. The date on-site construction for the installation of the emission control equipment identified in Attachment E for Cayuga Station Units 1 and 2 are initiated, and

    b. The date on-site construction for the installation of the emission control equipment identified in Attachment E for Cayuga Station Units 1 and 2 are completed.

    c. The date by which final compliance with 40 CFR 63, Subpart UUUUU for Cayuga Station Units 1 and 2 are achieved.

2. Duke Energy Indiana, Cayuga Station Units 1 and 2 are shall comply with the standards set forth in 40 CFR Part 63, Subpart UUUUU no later than April 16, 2016.

## SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description [326 IAC 2-7-5(15)]**

(j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]

(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)]**

E.5.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) 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).

(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.5.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]

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 F to this permit.

(1) 40 CFR 63.7485
(2) 40 CFR 63.7490(a)(1)
(3) 40 CFR 63.7490(d)
(4) 40 CFR 63.7499(o)
(5) 40 CFR 63.7500(c)
(6) 40 CFR 63.7500(f)
(7) 40 CFR 63.7515(d)
(8) 40 CFR 63.7550(b)
(9) 40 CFR 63.7550(c)(1)
(10) 40 CFR 63.7550(c)(5)(vi)
(11) 40 CFR 63.7550(c)(5)(xvii)
(12) 40 CFR 63.7550(h)(3)
(13) 40 CFR 63.7555(a)(1)
(14) 40 CFR 63.7560
(15) 40 CFR 63.7575

## SECTION F Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

**ORIS Code**: 1001

**CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 1 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, using #2 fuel oil for startup, shutdown, and stabilization purposes, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of $SO_2$, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), particulate matter (PM) and a continuous opacity monitor (COM). The COM will no longer be used for permit compliance purposes as of April 16, 2016 or when the PM CEM is installed, certified, and operating to measure PM pursuant to this permit. Boiler No. 2 was configured with a low $NO_X$ burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control $SO_3$, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

Under NESHAP Subpart UUUUU, this unit is part of an affected source.

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

F.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of the CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and CAIR NOx units, CAIR $SO_2$ units, and CAIR NOx ozone season units shall operate each unit in compliance with this CAIR permit.

(b) The CAIR NOx units, CAIR $SO_2$ units, and CAIR NOx ozone season units subject to this CAIR permit are Boiler No. 1 and Boiler No. 2.

F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit at the source shall comply with the monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source with the CAIR NOx emissions limitation under 326 IAC 24-1-4(c), CAIR $SO_2$ emissions limitation under 326 IAC 24-2-4(c), and CAIR NOx ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition F.4.1, Nitrogen Oxides Emission Requirements, Condition F.4.2, Sulfur Dioxide Emission Requirements, and Condition F.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR $NO_X$ source and each CAIR $NO_X$ unit at the source shall hold, in the source's compliance account, CAIR $NO_X$ allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR $NO_X$ units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR $NO_X$ unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.

(c) A CAIR $NO_X$ allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR $NO_X$ allowance was allocated.

(d) CAIR $NO_X$ allowances shall be held in, deducted from, or transferred into or among CAIR $NO_X$ allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR $NO_X$ allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR $NO_X$ annual trading program. No provision of the CAIR $NO_X$ annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR $NO_X$ allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR $NO_X$ allowance to or from a CAIR $NO_X$ source's compliance account is incorporated automatically in this CAIR permit.

F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR $SO_2$ source and each CAIR $SO_2$ unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR $SO_2$ allowances available for

compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR $SO_2$ units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR $SO_2$ unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.

(c) A CAIR $SO_2$ allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR $SO_2$ allowance was allocated.

(d) CAIR $SO_2$ allowances shall be held in, deducted from, or transferred into or among CAIR $SO_2$ allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR $SO_2$ allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR $SO_2$ trading program. No provision of the CAIR $SO_2$ trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR $SO_2$ allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR $SO_2$ allowance to or from a CAIR $SO_2$ source's compliance account is incorporated automatically in this CAIR permit.

F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR $NO_X$ ozone season source and each CAIR $NO_X$ ozone season unit at the source shall hold, in the source's compliance account, CAIR $NO_X$ ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR $NO_X$ ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR $NO_X$ ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.

(c) A CAIR $NO_X$ ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR $NO_X$ ozone season allowance was allocated.

(d) CAIR $NO_X$ ozone season allowances shall be held in, deducted from, or transferred into or among CAIR $NO_X$ ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR $NO_X$ ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR $NO_X$ ozone season trading program. No provision of the CAIR $NO_X$ ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be

construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR $NO_X$ ozone season allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR $NO_X$ ozone season allowance to or from a CAIR $NO_X$ ozone season source's compliance account is incorporated automatically in this CAIR permit.

F.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

(a) The owners and operators of a CAIR $NO_X$ source and each CAIR $NO_X$ unit that emits nitrogen oxides during any control period in excess of the CAIR $NO_X$ emissions limitation shall do the following:

(1) Surrender the CAIR $NO_X$ allowances required for deduction under 326 IAC 24-1-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

(b) The owners and operators of a CAIR $SO_2$ source and each CAIR $SO_2$ unit that emits sulfur dioxide during any control period in excess of the CAIR $SO_2$ emissions limitation shall do the following:

(1) Surrender the CAIR $SO_2$ allowances required for deduction under 326 IAC 24-2-8(k)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

(c) The owners and operators of a CAIR $NO_X$ ozone season source and each CAIR $NO_X$ ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR $NO_X$ ozone season emissions limitation shall do the following:

(1) Surrender the CAIR $NO_X$ ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

F.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx

ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program or to demonstrate compliance with the requirements of the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

F.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit at the source shall submit the reports required under the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the CAIR designated representative shall submit required information to:

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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the CAIR designated representative shall submit required information to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

F.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit shall be liable as follows:

(a) Each CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit shall meet the requirements of the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program.

(b) Any provision of the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program that applies to a CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source or the CAIR designated representative of a CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source shall also apply to the owners and operators of such source and of the CAIR NOx units, CAIR $SO_2$ units, and CAIR NOx ozone season units at the source

(c) Any provision of the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program that applies to a CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit or the CAIR designated representative of a CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit shall also apply to the owners and operators of such unit.

F.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NOx annual trading program, CAIR $SO_2$ trading program, and CAIR NOx ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOx source, CAIR $SO_2$ source, and CAIR NOx ozone season source or a CAIR NOx unit, CAIR $SO_2$ unit, and CAIR NOx ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

## F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR $NO_X$ source, CAIR $SO_2$ source, and CAIR $NO_X$ ozone season source, including all CAIR $NO_X$ units, CAIR $SO_2$ units, and CAIR $NO_X$ ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR $NO_X$ annual trading program, CAIR $SO_2$ trading program, and CAIR $NO_X$ ozone season trading program concerning the source or any CAIR $NO_X$ unit, CAIR $SO_2$ unit, and CAIR $NO_X$ ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR $NO_X$ source, CAIR $SO_2$ source, and CAIR $NO_X$ ozone season source choose to designate an alternate CAIR designated representative.

Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), whenever the term "CAIR designated representative" is used, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# COMPLIANCE AND ENFORCEMENT BRANCH
# PART 70 OPERATING PERMIT
# CERTIFICATION

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001

**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: |

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**
**OFFICE OF AIR QUALITY**
**COMPLIANCE AND ENFORCEMENT BRANCH**
**100 North Senate Avenue**
**MC 61-53 IGCN 1003**
**Indianapolis, Indiana 46204-2251**
**Phone: (317) 233-0178**
**Fax: (317) 233-6865**

**PART 70 OPERATING PERMIT**
**EMERGENCY OCCURRENCE REPORT**

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001

**This form consists of 2 pages** **Page 1 of 2**

| |
|---|
| ☐ This is an emergency as defined in 326 IAC 2-7-1(12)<br>• The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and<br>• The Permittee must submit notice in writing or by facsimile within 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 **Page 2 of 2**

| |
|---|
| Date/Time Emergency started: |
| Date/Time Emergency was corrected: |
| Was the facility being properly operated at the time of the emergency? Y N |
| Type of Pollutants Emitted: TSP, PM-10, $SO_2$, VOC, $NO_X$, CO, Pb, other: |
| Estimated amount of pollutant(s) emitted during emergency: |
| Describe the steps taken to mitigate the problem: |
| Describe the corrective actions/response steps taken: |
| Describe the measures taken to minimize emissions: |
| 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: |

Form Completed by: _____

Title / Position: _____

Date: _____

Phone:_____

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# COMPLIANCE AND ENFORCEMENT BRANCH

## Part 70 Quarterly Report

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001
Facility: Limestone Handling System
Parameter: Amount of limestone received
Limit: Less than 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month. (Condition D.5.1(a))

QUARTER:_____ YEAR:_____

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| Month 3 | | | |

☐ 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

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001
Facility: Gypsum Handling System
Parameter: The amount of gypsum received
Limit: Less than 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month. (Condition D.5.1(d))

QUARTER:_____ YEAR:_____

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| Month 3 | | | |

☐ 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

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001
Facility: Auxiliary Boiler (Aux)
Parameter: Fuel Usage
Limit: less than 455.2697 kilogallons of no. 2 fuel oil per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| Month 3 | | | |

☐ 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 OPERATING PERMIT
# QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Duke Energy Indiana, LLC - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T165-33876-00001

**Months: _____ to _____ Year: _____**

Page 1 of 2

| | |
|---|---|
| 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. 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 | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |

| | |
|---|---|
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

**Attachment F**

**Part 70 Operating Permit No: 165-33876-00001**

**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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

**§63.7495 When do I have to comply with this subpart?**

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

**Emission Limitations and Work Practice Standards**

**§63.7499 What are the subcategories of boilers and process heaters?**

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

**§63.7500 What emission limitations, work practice standards, and operating limits must I meet?**

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(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.

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

**§63.7501 [Reserved]**

**General Compliance Requirements**

**§63.7505 What are my general requirements for complying with this subpart?**

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(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.

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

**Testing, Fuel Analyses, and Initial Compliance Requirements**

**§63.7510 What are my initial compliance requirements and by what date must I conduct them?**

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(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.

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

**§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?**

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(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).

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

**§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.

[78 FR 7167, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

**§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.

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 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.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

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

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.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit

according to §63.7533, use the adjusted emission level for that unit, $E_{adj}$, determined according to §63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, $E_{adj}$, determined according to §63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

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

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance

demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

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.

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

**§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 ($CO_2$)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or $CO_2$) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or $CO_2$) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using $CO_2$ 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 $CO_2$ correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The 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.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an $CO_2$ analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be 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 $CO_2$ is used to correct CO emissions and $CO_2$ 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 $O_2$ both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and

reporting both the raw data (*e.g.,* hourly average wet-and dry basis $O_2$ values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or $CO_2$) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or $CO_2$) data concurrently. Collect at least four CO and oxygen (or $CO_2$) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an $CO_2$ percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

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

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in 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 ($SO_2$) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in 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 $SO_2$ CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The $SO_2$ CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the $SO_2$ CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the $SO_2$ CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting $SO_2$ data, you must operate the $SO_2$ CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when $SO_2$ data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured $SO_2$ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 $SO_2$ data and do not use part 75 substitute data values.

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

**§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?**

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine 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 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 Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury 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 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 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 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.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

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.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_{1,i}, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

$X_1$ = the PM CPMS data points for the three runs constituting the performance test,

$Y_1$ = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

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

$Y_1$ = the three run average lb/MMBtu PM concentration,

$X_1$ = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

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

Where:

$O_l$ = 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.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

$X_1$ = 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.

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

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 $SO_2$ CEMS is to install and operate the $SO_2$ according to the requirements in §63.7525(m) establish a maximum $SO_2$ emission rate equal to the highest hourly average $SO_2$ measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

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

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

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

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

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.

$$Metals = \sum_{i=1}^{n} \left( TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

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 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in 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 $SO_2$ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and $SO_2$ CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum $SO_2$ operating limit by collecting the maximum hourly $SO_2$ emission rate on the $SO_2$ CEMS during the paired 3-run test for HCl. The maximum $SO_2$ operating limit is equal to the highest hourly average $SO_2$ concentration measured during the HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015]

**§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:

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

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in §63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

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

Where:

$E_{adj}$ = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

$E_m$ = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under §63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

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**Continuous Compliance Requirements**

**§63.7535 Is there a minimum amount of monitoring data I must obtain?**

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

**§63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?**

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 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)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in 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 $NO_X$ requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date 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.

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

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

(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.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015]

**§63.7550 What reports must I submit and when?**

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

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

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

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

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit

using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

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

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, $SO_2$, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use

of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

**§63.7555 What records must I keep?**

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

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

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

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

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

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

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

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in 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.

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

**§63.7560 In what form and how long must I keep my records?**

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

**Other Requirements and Information**

**§63.7565 What parts of the General Provisions apply to me?**

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

**§63.7570 Who implements and enforces this subpart?**

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

**§63.7575 What definitions apply to this subpart?**

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

*10-day rolling average* means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

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

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

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

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

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

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

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

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

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

*Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as

defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

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

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

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

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

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

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

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

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

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

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

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

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

(2) A deviation is not always a violation.

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

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

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

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

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

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

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

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

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

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

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

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

*Energy management practices* means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy

performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

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

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

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

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

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

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

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

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

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

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

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

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

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

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

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

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

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

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

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

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

*Minimum sorbent injection rate* means:

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

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

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

*Natural gas* means:

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

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

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

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

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

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

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

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

*Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

*Oxygen trim system* means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

*Particulate matter (PM)* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

*Period of gas curtailment or supply interruption* means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

*Pile burner* means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for

combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

*Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

*Pulverized coal boiler* means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

*Qualified energy assessor* means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

*Refinery gas* means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

*Regulated gas stream* means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

*Residential boiler* means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* §63.14(b)).

*Responsible official* means responsible official as defined in §70.2.

*Rolling average* means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

*Secondary material* means the material as defined in §241.2 of this chapter.

*Shutdown* means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

*Sloped grate* means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

*Solid fossil fuel* includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

*Solid fuel* means any solid fossil fuel or biomass or bio-based solid fuel.

*Startup* means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

*Steam output* means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating ($S_1$), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition ($S_2$), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, $S_1$, $S_2$, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)} \; x \; CFn) \qquad \text{(Eq. 21)}$$

Where:

$SO_M$ = Total steam output for multi-function boiler, MMBtu

$S_1$ = Energy content of steam sent directly to the process and/or used for heating, MMBtu

$S_2$ = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

*Stoker* means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

*Stoker/sloped grate/other unit designed to burn kiln dried biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

*Stoker/sloped grate/other unit designed to burn wet biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

*Suspension burner* means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

*Temporary boiler* means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

*Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

*Traditional fuel* means the fuel as defined in §241.2 of this chapter.

*Tune-up* means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).

*Ultra low sulfur liquid fuel* means a distillate oil that has less than or equal to 15 ppm sulfur.

*Unit designed to burn biomass/bio-based solid subcategory* includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

*Unit designed to burn coal/solid fossil fuel subcategory* includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

*Unit designed to burn gas 2 (other) subcategory* includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

*Unit designed to burn heavy liquid subcategory* means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

*Unit designed to burn light liquid subcategory* means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

*Unit designed to burn liquid subcategory* includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

*Unit designed to burn liquid fuel that is a non-continental unit* means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Unit designed to burn solid fuel subcategory* means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

*Useful thermal energy* means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

*Vegetable oil* means oils extracted from vegetation.

*Voluntary Consensus Standards or VCS* mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211

Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

*Waste heat boiler* means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

*Waste heat process heater* means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

**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 . . .** |
|---|---|---|---|---|
| 1. Units in all subcategories designed to burn solid fuel. | a. HCl | 2.2E-02 lb per MMBtu of heat input | 2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh | For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run. |

| 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 | 8.0E-07[a] lb per MMBtu of heat input | 8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 2. Units designed to burn coal/solid fossil fuel | a. Filterable PM (or TSM) | 1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input) | 1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 3. Pulverized coal boilers designed to burn coal/solid fossil fuel | a. Carbon monoxide (CO) (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 4. Stokers/others designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 5. Fluidized bed units designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 7. Stokers/sloped grate/others designed to burn wet biomass fuel | a. CO (or CEMS) | 620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average | 1 hr minimum sampling time. |

| **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. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input) | 3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel | a. CO | 460 ppm by volume on a dry basis corrected to 3 percent oxygen | 4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input) | 3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 9. Fluidized bed units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input) | 1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04[a] lb per MMBtu of steam output or 1.2E-03[a] lb per MWh) | Collect a minimum of 3 dscm per run. |
| 10. Suspension burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average) | 1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | 3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |

| **If your boiler or process heater is in this subcategory . . .** | **For the following pollutants . . .** | **The emissions must not exceed the following emission limits, except during startup and shutdown . . .** | **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 . . .** |
|---|---|---|---|---|
| 11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average) | 3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | 4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 12. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen | 1.1 lb per MMBtu of steam output or 1.0E + 01 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.0E-02 lb per MMBtu of heat input; or (2.9E-05[a] lb per MMBtu of heat input) | 3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids | a. CO (or CEMS) | 1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average) | 1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input) | 3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 14. Units designed to burn liquid fuel | a. HCl | 4.4E-04 lb per MMBtu of heat input | 4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh | For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |

| 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[a] lb per MMBtu of heat input | 5.3E-07[a] lb per MMBtu of steam output or 6.7E-06[a] lb per MWh | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 15. Units designed to burn heavy liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input) | 1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 16. Units designed to burn light liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | 1.2E-03[a] lb per MMBtu of steam output or 1.6E-02[a] lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 17. Units designed to burn liquid fuel that are non-continental units | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input) | 2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh) | Collect a minimum of 4 dscm per run. |
| 18. Units designed to burn gas 2 (other) gases | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen | 0.16 lb per MMBtu of steam output or 1.0 lb per MWh | 1 hr minimum sampling time. |
| | b. HCl | 1.7E-03 lb per MMBtu of heat input | 2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh | For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |

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

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in 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.

[d]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.

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

**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]

| **If your boiler or process heater is in this subcategory . . .** | **For the following pollutants . . .** | **The emissions must not exceed the following emission limits, except during startup and shutdown . . .** | **The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .** | **Using this specified sampling volume or test run duration . . .** |
|---|---|---|---|---|
| 1. Units in all subcategories designed to burn solid fuel | a. HCl | 2.2E-02 lb per MMBtu of heat input | 2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh | For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run. |
| | b. Mercury | 5.7E-06 lb per MMBtu of heat input | 6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh | For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm. |
| 2. Units design to burn coal/solid fossil fuel | a. Filterable PM (or TSM) | 4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input) | 4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 3. Pulverized coal boilers designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 4. Stokers/others designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 5. Fluidized bed units designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |

| **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 . . .** |
|---|---|---|---|---|
| 6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| 7. Stokers/sloped grate/others designed to burn wet biomass fuel | a. CO (or CEMS) | 1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input) | 4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel | a. CO | 460 ppm by volume on a dry basis corrected to 3 percent oxygen | 4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input) | 3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh) | Collect a minimum of 1 dscm per run. |
| 9. Fluidized bed units designed to burn biomass/bio-based solid | a. CO (or CEMS) | 470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input) | 1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh) | Collect a minimum of 1 dscm per run. |

| **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 . . .** |
|---|---|---|---|---|
| 10. Suspension burners designed to burn biomass/bio-based solid | a. CO (or CEMS) | 2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | 5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid | a. CO (or CEMS) | 770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input) | 3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh) | Collect a minimum of 1 dscm per run. |
| 12. Fuel cell units designed to burn biomass/bio-based solid | a. CO | 1,100 ppm by volume on a dry basis corrected to 3 percent oxygen | 2.4 lb per MMBtu of steam output or 12 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input) | 5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 13. Hybrid suspension grate units designed to burn biomass/bio-based solid | a. CO (or CEMS) | 3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average | 1 hr minimum sampling time. |

| 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 . . . |
|---|---|---|---|---|
| | b. Filterable PM (or TSM) | 4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input) | 5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh) | Collect a minimum of 1 dscm per run. |
| 14. Units designed to burn liquid fuel | a. HCl | 1.1E-03 lb per MMBtu of heat input | 1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh | For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |
| | b. Mercury | 2.0E-06[a] lb per MMBtu of heat input | 2.5E-06[a] lb per MMBtu of steam output or 2.8E-05 lb per MWh | For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784,[b] collect a minimum of 2 dscm. |
| 15. Units designed to burn heavy liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input) | 7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh) | Collect a minimum of 1 dscm per run. |
| 16. Units designed to burn light liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 7.9E-03[a] lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input) | 9.6E-03[a] lb per MMBtu of steam output or 1.1E-01[a] lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 17. Units designed to burn liquid fuel that are non-continental units | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test | 0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input) | 3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |

| **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 D6784[b] collect a minimum of 2 dscm. |
| | d. Filterable PM (or TSM) | 6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input) | 1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh) | Collect a minimum of 3 dscm per run. |

[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.

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

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

As stated in §63.7500, you must comply with the following applicable work practice standards:

| **If your unit is . . .** | **You must meet the following . . .** |
|---|---|
| 1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater | Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540. |
| 2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid | Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540. |
| 3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater | Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans. |
| 4. An existing boiler or process heater located at a major source facility, not including limited use units | Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575: |
| | a. A visual inspection of the boiler or process heater system. |
| | b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. |
| | c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. |

| If your unit is . . . | You must meet the following . . . |
|---|---|
| | d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. |
| | e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. |
| | f. A list of cost-effective energy conservation measures that are within the facility's control. |
| | g. A list of the energy savings potential of the energy conservation measures identified. |
| | h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments. |
| 5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup | a. You must operate all CMS during startup.<br>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.<br>c. You have the option of complying using either of the following work practice standards.<br>(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<br>(2) If you choose to comply using definition (2) of “startup” in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e).<br>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.<br>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.<br>If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.<br>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).<br>You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555. |

[a]As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

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

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

As stated in §63.7500, you must comply with the applicable operating limits:

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

| When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . . | You must meet these operating limits . . . |
|---|---|
| 1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS | Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to §63.7530(b) and Table 7 to this subpart. |
| 2. Wet acid gas (HCl) scrubber[a] control on a boiler or process heater not using a HCl CEMS | Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to §63.7530(b) and Table 7 to this subpart. |
| 3. Fabric filter control on a boiler or process heater not using a PM CPMS | a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or |

| When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . . | You must meet these operating limits . . . |
|---|---|
| | b. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period. |
| 4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS | a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average). |
| | b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to this subpart. |
| 5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS | Maintain the minimum sorbent or carbon injection rate as defined in §63.7575 of this subpart. |
| 6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS | This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average). |
| 7. Performance testing | For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test. |
| 8. Oxygen analyzer system | For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an $O_2$ analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a). |
| 9. $SO_2$ CEMS | For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an $SO_2$ CEMS, maintain the 30-day rolling average $SO_2$ emission rate at or below the highest hourly average $SO_2$ concentration measured during the HCl performance test, as specified in Table 8. |

[a]A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]

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

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

| To conduct a performance test for the following pollutant . . . | You must. . . | Using, as appropriate . . . |
|---|---|---|
| 1. Filterable PM | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter. |
| | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a] |
| | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
| | e. Measure the PM emission concentration | Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter. |
| | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 2. TSM | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter. |
| | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a] |
| | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
| | e. Measure the TSM emission concentration | Method 29 at 40 CFR part 60, appendix A-8 of this chapter |
| | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 3. Hydrogen chloride | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter. |
| | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a] |

| To conduct a performance test for the following pollutant . . . | You must. . . | Using, as appropriate . . . |
|---|---|---|
| | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
| | e. Measure the hydrogen chloride emission concentration | Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter. |
| | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 4. Mercury | a. Select sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas | Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter. |
| | c. Determine oxygen or carbon dioxide concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a] |
| | d. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
| | e. Measure the mercury emission concentration | Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a] |
| | f. Convert emissions concentration to lb per MMBtu emission rates | Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter. |
| 5. CO | a. Select the sampling ports location and the number of traverse points | Method 1 at 40 CFR part 60, appendix A-1 of this chapter. |
| | b. Determine oxygen concentration of the stack gas | Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a] |
| | c. Measure the moisture content of the stack gas | Method 4 at 40 CFR part 60, appendix A-3 of this chapter. |
| | d. Measure the CO emission concentration | Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit. |

[a]Incorporated by reference, see §63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

**Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements**

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

| To conduct a fuel analysis for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| 1. Mercury | a. Collect fuel samples | Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent. |
| | b. Composite fuel samples | Procedure in §63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821-R-01-013[a] (for liquid or solid), or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173,[a] ASTM E871,[a] or ASTM D5864,[a] or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent. |
| | f. Measure mercury concentration in fuel sample | ASTM D6722[a] (for coal), EPA SW-846-7471B[a] or EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470A[a] (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent. |
| | g. Convert concentration into units of pounds of mercury per MMBtu of heat content | For fuel mixtures use Equation 8 in §63.7530. |
| 2. HCl | a. Collect fuel samples | Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent. |
| | b. Composite fuel samples | Procedure in §63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), or ASTM D5198[a] (for biomass), or EPA 3050[a] or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173[a] or ASTM E871,[a] or D5864,[a] or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent. |
| | f. Measure chlorine concentration in fuel sample | EPA SW-846-9250,[a] ASTM D6721,[a] ASTM D4208[a] (for coal), or EPA SW-846-5050[a] or ASTM E776[a] (for solid fuel), or EPA SW-846-9056[a] or SW-846-9076[a] (for solids or liquids) or equivalent. |

| To conduct a fuel analysis for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| | g. Convert concentrations into units of pounds of HCl per MMBtu of heat content | For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028. |
| 3. Mercury Fuel Specification for other gas 1 fuels | a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or | Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954,[a] ASTM D6350,[a] ISO 6978-1:2003(E),[a] or ISO 6978-2:2003(E),[a] or EPA-1631[a] or equivalent. |
| | b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater | Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent. |
| 4. TSM | a. Collect fuel samples | Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177,[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent. |
| | b. Composite fuel samples | Procedure in §63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173[a] or ASTM E871,[a] or D5864, or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent. |
| | f. Measure TSM concentration in fuel sample | ASTM D3683,[a] or ASTM D4606,[a] or ASTM D6357[a] or EPA 200.8[a] or EPA SW-846-6020,[a] or EPA SW-846-6020A,[a] or EPA SW-846-6010C,[a] EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW-846-7740[a] (for selenium only). |
| | g. Convert concentrations into units of pounds of TSM per MMBtu of heat content | For fuel mixtures use Equation 9 in §63.7530. |

[a]Incorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]

**Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limitsab**

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits[ab]

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

| **If you have an applicable emission limit for . . .** | **And your operating limits are based on . . .** | **You must . . .** | **Using . . .** | **According to the following requirements** |
|---|---|---|---|---|
| 2. HCl | a. Wet scrubber operating parameters | i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b) | (1) Data from the pH and liquid flow-rate monitors and the HCl performance test | (a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.<br>(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. |
| | b. Dry scrubber operating parameters | i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent | (1) Data from the sorbent injection rate monitors and HCl or mercury performance test | (a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.<br>(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.<br>(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate. |
| | c. Alternative Maximum $SO_2$emission rate | i. Establish a site-specific maximum $SO_2$emission rate operating limit according to §63.7530(b) | (1) Data from $SO_2$ CEMS and the HCl performance test | (a) You must collect the $SO_2$ emissions data according to §63.7525(m) during the most recent HCl performance tests.<br>(b) The maximum $SO_2$emission rate is equal to the highest hourly average $SO_2$emission rate measured during the most recent HCl performance tests. |

| **If you have an applicable emission limit for . . .** | **And your operating limits are based on . . .** | **You must . . .** | **Using . . .** | **According to the following 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.<br>(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.<br>(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.<br>(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.<br>(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.<br>(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.<br>(c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit. |

[a]Operating limits must be confirmed or reestablished during performance tests.

[b]If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

[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:

| **If you must meet the following operating limits or work practice standards . . .** | **You must demonstrate continuous compliance by . . .** |
|---|---|
| 1. Opacity | a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and |
| | b. Reducing the opacity monitoring data to 6-minute averages; and |
| | c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation. |
| 2. PM CPMS | a. Collecting the PM CPMS output data according to §63.7525; |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4). |
| 3. Fabric Filter Bag Leak Detection Operation | Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met. |
| 4. Wet Scrubber Pressure Drop and Liquid Flow-rate | a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(b). |
| 5. Wet Scrubber pH | a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b). |
| 6. Dry Scrubber Sorbent or Carbon Injection Rate | a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575. |
| 7. Electrostatic Precipitator Total Secondary Electric Power Input | a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and |
| | b. Reducing the data to 30-day rolling averages; and |

| If you must meet the following operating limits or work practice standards . . . | You must demonstrate continuous compliance by . . . |
|---|---|
| | c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to §63.7530(b). |
| 8. Emission limits using fuel analysis | a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and |
| | b. Reduce the data to 12-month rolling averages; and |
| | c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart. |
| | d. Calculate the HCI, 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. |
| 9. Oxygen content | a. Continuously monitor the oxygen content using an oxygen analyzer system according to §63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a)(7). |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test. |
| 10. Boiler or process heater operating load | a. Collecting operating load data or steam generation data every 15 minutes.<br>b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c). |
| 11. $SO_2$ emissions using $SO_2$ CEMS | a. Collecting the $SO_2$ CEMS output data according to §63.7525; |
| | b. Reducing the data to 30-day rolling averages; and |
| | c. Maintaining the 30-day rolling average $SO_2$ CEMS emission rate to a level at or below the highest hourly $SO_2$ rate measured during the HCl performance test according to §63.7530. |

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

**Table 9 to Subpart DDDDD of Part 63—Reporting Requirements**

As stated in §63.7550, you must comply with the following requirements for reports:

| You must submit a(n) | The report must contain . . . | You must submit the report . . . |
|---|---|---|
| 1. Compliance report | a. Information required in §63.7550(c)(1) through (5); and | Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b). |

| 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) | |

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

**Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD**

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

| Citation | Subject | Applies to subpart DDDDD |
|---|---|---|
| §63.1 | Applicability | Yes. |
| §63.2 | Definitions | Yes. Additional terms defined in §63.7575 |
| §63.3 | Units and Abbreviations | Yes. |
| §63.4 | Prohibited Activities and Circumvention | Yes. |
| §63.5 | Preconstruction Review and Notification Requirements | Yes. |
| §63.6(a), (b)(1)-(b)(5), (b)(7), (c) | Compliance with Standards and Maintenance Requirements | Yes. |
| §63.6(e)(1)(i) | General duty to minimize emissions. | No. See §63.7500(a)(3) for the general duty requirement. |
| §63.6(e)(1)(ii) | Requirement to correct malfunctions as soon as practicable. | No. |
| §63.6(e)(3) | Startup, shutdown, and malfunction plan requirements. | No. |

| Citation | Subject | Applies to subpart DDDDD |
|---|---|---|
| §63.6(f)(1) | Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards. | No. |
| §63.6(f)(2) and (3) | Compliance with non-opacity emission standards. | Yes. |
| §63.6(g) | Use of alternative standards | Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2). |
| §63.6(h)(1) | Startup, shutdown, and malfunction exemptions to opacity standards. | No. See §63.7500(a). |
| §63.6(h)(2) to (h)(9) | Determining compliance with opacity emission standards | No. Subpart DDDDD specifies opacity as an operating limit not an emission standard. |
| §63.6(i) | Extension of compliance | Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart. |
| §63.6(j) | Presidential exemption. | Yes. |
| §63.7(a), (b), (c), and (d) | Performance Testing Requirements | Yes. |
| §63.7(e)(1) | Conditions for conducting performance tests | No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c). |
| §63.7(e)(2)-(e)(9), (f), (g), and (h) | Performance Testing Requirements | Yes. |
| §63.8(a) and (b) | Applicability and Conduct of Monitoring | Yes. |
| §63.8(c)(1) | Operation and maintenance of CMS | Yes. |
| §63.8(c)(1)(i) | General duty to minimize emissions and CMS operation | No. See §63.7500(a)(3). |
| §63.8(c)(1)(ii) | Operation and maintenance of CMS | Yes. |
| §63.8(c)(1)(iii) | Startup, shutdown, and malfunction plans for CMS | No. |
| §63.8(c)(2) to (c)(9) | Operation and maintenance of CMS | Yes. |
| §63.8(d)(1) and (2) | Monitoring Requirements, Quality Control Program | Yes. |

| Citation | Subject | Applies to subpart DDDDD |
|---|---|---|
| §63.8(d)(3) | Written procedures for CMS | Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required. |
| §63.8(e) | Performance evaluation of a CMS | Yes. |
| §63.8(f) | Use of an alternative monitoring method. | Yes. |
| §63.8(g) | Reduction of monitoring data | Yes. |
| §63.9 | Notification Requirements | Yes. |
| §63.10(a), (b)(1) | Recordkeeping and Reporting Requirements | Yes. |
| §63.10(b)(2)(i) | Recordkeeping of occurrence and duration of startups or shutdowns | Yes. |
| §63.10(b)(2)(ii) | Recordkeeping of malfunctions | No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions. |
| §63.10(b)(2)(iii) | Maintenance records | Yes. |
| §63.10(b)(2)(iv) and (v) | Actions taken to minimize emissions during startup, shutdown, or malfunction | No. |
| §63.10(b)(2)(vi) | Recordkeeping for CMS malfunctions | Yes. |
| §63.10(b)(2)(vii) to (xiv) | Other CMS requirements | Yes. |
| §63.10(b)(3) | Recordkeeping requirements for applicability determinations | No. |
| §63.10(c)(1) to (9) | Recordkeeping for sources with CMS | Yes. |
| §63.10(c)(10) and (11) | Recording nature and cause of malfunctions, and corrective actions | No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions. |
| §63.10(c)(12) and (13) | Recordkeeping for sources with CMS | Yes. |
| §63.10(c)(15) | Use of startup, shutdown, and malfunction plan | No. |
| §63.10(d)(1) and (2) | General reporting requirements | Yes. |
| §63.10(d)(3) | Reporting opacity or visible emission observation results | No. |
| §63.10(d)(4) | Progress reports under an extension of compliance | Yes. |
| §63.10(d)(5) | Startup, shutdown, and malfunction reports | No. See §63.7550(c)(11) for malfunction reporting requirements. |

| Citation | Subject | Applies to subpart DDDDD |
|---|---|---|
| §63.10(e) | Additional reporting requirements for sources with CMS | Yes. |
| §63.10(f) | Waiver of recordkeeping or reporting requirements | Yes. |
| §63.11 | Control Device Requirements | No. |
| §63.12 | State Authority and Delegation | Yes. |
| §63.13-63.16 | Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions | Yes. |
| §63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9). | Reserved | No. |

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

**Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011**

| If your boiler or process heater is in this subcategory . . . | For the following pollutants . . . | The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . . | Using this specified sampling volume or test run duration . . . |
|---|---|---|---|
| 1. Units in all subcategories designed to burn solid fuel | a. HCl | 0.022 lb per MMBtu of heat input | For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run. |
| 2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis | a. Mercury | 8.0E-07[a] lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis | a. Mercury | 2.0E-06 lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 4. Units design to burn coal/solid fossil fuel | a. Filterable PM (or TSM) | 1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |

| 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 . . . |
|---|---|---|---|
| 5. Pulverized coal boilers designed to burn coal/solid fossil fuel | a. Carbon monoxide (CO) (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| 6. Stokers designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| 7. Fluidized bed units designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| 8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| 9. Stokers/sloped grate/others designed to burn wet biomass fuel | a. CO (or CEMS) | 620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel | a. CO | 560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 11. Fluidized bed units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |

| 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,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 14. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen, 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,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 16. Units designed to burn liquid fuel | a. HCl | 4.4E-04 lb per MMBtu of heat input | For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |
| | b. Mercury | 4.8E-07[a] lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 17. Units designed to burn heavy liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |

| 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 . . . |
|---|---|---|---|
| | b. Filterable PM (or TSM) | 1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 18. Units designed to burn light liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.0E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 19. Units designed to burn liquid fuel that are non-continental units | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test | 1 hr minimum sampling time. |
| | b. Filterable 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[b] collect a minimum of 3 dscm. |
| | d. Filterable PM (or TSM) | 6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may 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.

[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**

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

| **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<br>b. Filterable PM (or TSM) | 460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average<br>3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input) | 1 hr minimum sampling time. Collect a minimum of 2 dscm per run. |
| 9. Fluidized bed units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 10. Suspension burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 12. Fuel cell units designed to burn biomass/bio-based solids | a. CO<br>b. Filterable PM (or TSM) | 910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average<br>2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | 1 hr minimum sampling time. Collect a minimum of 2 dscm per run. |
| 13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids | a. CO (or CEMS) | 1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 14. Units designed to burn liquid fuel | a. HCl | 4.4E-04 lb per MMBtu of heat input | For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |

| **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 . . .** |
|---|---|---|---|
| | b. Mercury | 4.8E-07[a] lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 15. Units designed to burn heavy liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 16. Units designed to burn light liquid fuel | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.3E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 17. Units designed to burn liquid fuel that are non-continental units | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input) | Collect a minimum of 4 dscm per run. |
| 18. Units designed to burn gas 2 (other) gases | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average | 1 hr minimum sampling time. |
| | b. HCl | 1.7E-03 lb per MMBtu of heat input | For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |
| | c. Mercury | 7.9E-06 lb per MMBtu of heat input | For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm. |
| | d. Filterable PM (or TSM) | 6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may 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.

[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**

| **If your boiler or process heater is in this subcategory . . .** | **For the following pollutants . . .** | **The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .** | **Using this specified sampling volume or test run duration . . .** |
|---|---|---|---|
| 1. Units in all subcategories designed to burn solid fuel | a. HCl | 0.022 lb per MMBtu of heat input | For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run. |
| | b. Mercury | 8.6E-07[a] lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 2. Pulverized coal boilers designed to burn coal/solid fossil fuel | a. Carbon monoxide (CO) (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 3. Stokers designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 4. Fluidized bed units designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel | a. CO (or CEMS) | 140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |

| **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 . . .** |
|---|---|---|---|
| | b. Filterable PM (or TSM) | 1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 6. Stokers/sloped grate/others designed to burn wet biomass fuel | a. CO (or CEMS) | 620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel | a. CO | 460 ppm by volume on a dry basis corrected to 3 percent oxygen | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 8. Fluidized bed units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run.* |
| 9. Suspension burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 11. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids | a. CO (or CEMS) | 1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average) | 1 hr minimum sampling time. |

| **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 . . .** |
|---|---|---|---|
| | b. Filterable PM (or TSM) | 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 13. Units designed to burn liquid fuel | a. HCl | 1.2E-03 lb per MMBtu of heat input | For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |
| | b. Mercury | 4.9E-07[a] lb per MMBtu of heat input | For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm. |
| 14. Units designed to burn heavy liquid fuel | a. CO (or CEMS) | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average) | 1 hr minimum sampling time. |
| 15. Units designed to burn light liquid fuel | a. CO (or CEMS) | 130[a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |
| 16. Units designed to burn liquid fuel that are non-continental units | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average) | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input) | Collect a minimum of 2 dscm per run. |
| 17. Units designed to burn gas 2 (other) gases | a. CO | 130 ppm by volume on a dry basis corrected to 3 percent oxygen | 1 hr minimum sampling time. |
| | b. HCl | 1.7E-03 lb per MMBtu of heat input | For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. |
| | c. Mercury | 7.9E-06 lb per MMBtu of heat input | For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm. |
| | d. Filterable PM (or TSM) | 6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input) | Collect a minimum of 3 dscm per run. |

[a]If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to §63.7515 if all of the other provision of

§63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b]Incorporated by reference, see §63.14.

[c]An owner or operator may 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.

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

# Indiana Department of Environmental Management
# Office of Air Quality

## Technical Support Document (TSD) for a Part 70 Significant Permit Modification

### Source Description and Location

| | |
|---|---|
| **Source Name:** | **Duke Energy Indiana, LLC - Cayuga Generating Station** |
| **Source Location:** | **SR 63, Cayuga, IN 47928** |
| **County:** | **Vermillion** |
| **SIC Code:** | **4911** |
| **Operation Permit No.:** | **T 165-33876-00001** |
| **Operation Permit Issuance Date:** | **May 8, 2014** |
| **Significant Permit Modification No.:** | **165-36707-00001** |
| **Permit Reviewer:** | **Josiah Balogun** |

### Source Definition

This stationary electric utility generating station consists of two (2) plants:

(a) Duke Energy Indiana, LLC - Cayuga Generating Station is located at SR 63, Cayuga, IN 47928; and

(b) Duke Energy Indiana, LLC - Cayuga Generating Station Unit 4 combustion turbine plant is located at SR 63, Cayuga IN, 47928

However, these plants are located on the same piece of property, have the same SIC codes and are under common control; therefore they are considered one (1) source, as defined by 326 IAC 2-7-1(22). This conclusion was initially determined under Part 70 Operating Permit Renewal T165-33876-00001 on May 8, 2014.

### Existing Approvals

The source was issued Part 70 Operating Permit No. 165-33876-00001 on May 8, 2014. The source has since received the following approvals:

(a) Administrative Amendment No. 165-35161-00001, issued on December 17, 2014;

(b) Acid Rain Administrative Amendment No. 165-35230-00001, issued on December 17, 2014;

(c) Significant Permit Modification No.165-34940-00001, issued on December 24, 2014;

(d) Significant Permit Modification No. 165-35734-00001, issued on September 8, 2015; and

(e) Acid Rain Permit No. 165-35804-00001, issued on September 21, 2015;

## County Attainment Status

The source is located in Vermillion County.

| Pollutant | Designation |
|---|---|
| $SO_2$ | Better than national standards. |
| CO | Unclassifiable or attainment effective November 15, 1990. |
| $O_3$ | Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.[1] |
| $PM_{2.5}$ | Unclassifiable or attainment effective April 5, 2005, for the annual $PM_{2.5}$ standard. |
| $PM_{2.5}$ | Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard. |
| $PM_{10}$ | Attainment effective October 27, 1997, for the part of Clinton Township that includes sections 15, 16, 21, 22, 27, 28, 33, and 34. Unclassifiable effective November 15, 1990, for the remainder of Vermillion County. |
| $NO_2$ | Cannot be classified or better than national standards. |
| Pb | Unclassifiable or attainment effective December 31, 2011. |
| [1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. | |

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides ($NO_x$) 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 $NO_x$ emissions are considered when evaluating the rule applicability relating to ozone. Vermillion County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and $NO_x$ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Vermillion County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, $SO_2$, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Vermillion County has been classified as attainment or unclassifiable in Indiana for PM10, PM2.5, NOx, SO2, CO and Pb. 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 fossil fuel-fired steam electric plant of more than two hundred fifty million (250,000,000) British thermal units per hour heat input, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

## Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

| **Pollutant** | **Emissions** (ton/yr) |
|---|---|
| PM | 2,023 |
| $PM_{10}$ | 482 |
| $PM_{2.5}$ | 478 |
| $SO_2$ | 124,272 |
| $NO_X$ | 10,997 |
| VOC | 120 |
| CO | 1,019 |
| Single HAP | > 10 |
| Total HAPs | 2,680 |

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 GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant, 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) These emissions are based upon Part 70 Operating Permit No. T165-36292-00001, issued on October 2, 2015

(c) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and 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).

## Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Duke Energy Indiana, LLC - Cayuga Generating Station on January 13, 2016, relating to the auxiliary boiler identified as Aux, that is subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters - 40 CFR Part 63 Subpart DDDDD and the Limited Use provisions of the Industrial Boiler MACT Rule. The source is also changing the name of the plant to Duke Energy Indiana, LLC.

## Enforcement Issues

There are no pending enforcement actions.

## Permit Level Determination – Part 70 Modification to an Existing Source

There is no increase in the potential to emit of any regulated pollutants associated with this modification. This modification is not subject to the source modification requirements under 326 IAC 2-7-10.5. The changes will be incorporated into the permit as a Significant Permit Modification under 326 IAC 2-7-12, because the modification involves the addition of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters - 40 CFR Part 63 Subpart DDDDD (Boiler MACT) which involves significant changes to existing monitoring, reporting, and record keeping requirements.

## Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

**NSPS:**

(a) There are no New Source Performance Standards (NSPS)(326 IAC 12 and 40 CFR Part 60) applicable to this proposed modification.

**NESHAP:**

(b) **40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters:**

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 No. 2 fuel oil-fired boiler, identified as Aux is 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 unit subject to this rule includes the following:

(1) **One (1)** Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [**Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source**]

This emission unit is 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 63.7499(o)
(5) 40 CFR 63.7500(c)

(6) 40 CFR 63.7500(f)
(7) 40 CFR 63.7515(d)
(8) 40 CFR 63.7550(b)
(9) 40 CFR 63.7550(c)(1)
(10) 40 CFR 63.7550(c)(5)(vi)
(11) 40 CFR 63.7550(c)(5)(xvii)
(12) 40 CFR 63.7550(h)(3)
(13) 40 CFR 63.7555(a)(1)
(14) 40 CFR 63.7560
(15) 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.

(c) There are no other National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed modification.

## State Rule Applicability Determination

The following state rules are applicable to the source due to the modification:

**326 IAC 2-2 (PSD)**
PSD applicability is discussed under the Permit Level Determination – PSD section.

## Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure 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.
The new Compliance Determination and Monitoring Requirements included in this modification are under 40 CFR 63, Subpart DDDDD.

## Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. 165-33876-00001. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

**Change 1:** The emission unit description has been updated in Section A.3 - Emission Units and Pollution Control Equipment Summary of the permit accordingly.

A.3 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:

**********

(j) **One (1)** Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [**Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source**]

**********

**Change 2:** The limited use conditions have been added to Section D.6 for the auxiliary boiler, identified as Aux accordingly.

**SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS**

**Emissions Unit Description:**

(j) **One (1)** Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [**Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source**]

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

**In order to render auxiliary boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c), the Permittee shall comply with the following:**

**The fuel usage of the auxiliary boiler, identified as Aux shall not exceed 455.2697 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 boiler, identified as Aux a limited use boiler pursuant to 40 CFR 63.7500(c).**

**********

**Compliance Determination Requirements [326 IAC 2-7-6]**

D.6.4 Sulfur Dioxide Emissions and Sulfur Content **[326 IAC 2-7-6]**

Compliance shall be determined utilizing one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per million Btu heat input by:

**********

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

D.6.5 Visible Emissions Notations **[326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]**

(a) Visible emission notations of the Auxiliary Boiler stack exhaust (Aux-1) shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

**********

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

D.6.6 Record Keeping Requirement **[326 IAC 2-7-5(3)][326 IAC 2-7-19]**

**********

**(c) To document the compliance status with Condition D.6.0, the Permittee shall maintain records of fuel usage for the days the boiler, identified as Aux is operating.**

(~~c~~**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 [326 IAC 2-7-5(3)][326 IAC 2-7-19]**

**A quarterly report of the information to document the compliance status with Condition D.6.0 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.**

**Change 3:** A new section has been added in Section E to include the provisions of the Boiler MACT, 40 CFR 63, Subpart DDDDD for the auxiliary boiler.

**SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS**

**Emissions Unit Description [326 IAC 2-7-5(15)]**

**(j) One (1) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968. [Under NESHAP 40 CFR 63, Subpart DDDDD, this unit is part of an affected source]**

(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)]**

**E.5.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]**

**(a) 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).**

**(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.5.2 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [326 IAC 20-95] [40 CFR Part 63, Subpart DDDDD]**

**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 F to this permit.**

**(1) 40 CFR 63.7485**
**(2) 40 CFR 63.7490(a)(1)**
**(3) 40 CFR 63.7490(d)**
**(4) 40 CFR 63.7499(o)**
**(5) 40 CFR 63.7500(c)**
**(6) 40 CFR 63.7500(f)**
**(7) 40 CFR 63.7515(d)**
**(8) 40 CFR 63.7550(b)**
**(9) 40 CFR 63.7550(c)(1)**
**(10) 40 CFR 63.7550(c)(5)(vi)**
**(11) 40 CFR 63.7550(c)(5)(xvii)**
**(12) 40 CFR 63.7550(h)(3)**
**(13) 40 CFR 63.7555(a)(1)**
**(14) 40 CFR 63.7560**
**(15) 40 CFR 63.7575**

**Change 4:** A new reporting form has been added at the back of the permit to report the fuel usage for the auxiliary boiler.

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# COMPLIANCE AND ENFORCEMENT BRANCH

## Part 70 Quarterly Report

**Source Name:** **Duke Energy Indiana, LLC - Cayuga Generating Station**
**Source Address:** **State Road 63, Cayuga, Indiana 47928**
**Part 70 Permit No.:** **T165-33876-00001**
**Facility:** **Auxiliary Boiler (Aux)**
**Parameter:** **Fuel Usage**
**Limit:** **less than 455.2697 kilogallons of no. 2 fuel oil per twelve (12) consecutive month period with compliance determined at the end of each month.**

**QUARTER:**_____ **YEAR:**_____

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| | | | |

| | | | |
|---|---|---|---|
| **Month 3** | | | |

☐ **No deviation occurred in this quarter.**
☐ **Deviation/s occurred in this quarter.**
**Deviation has been reported on:** _____

**Submitted by:** _____

**Title / Position:** _____

**Signature:** _____

**Date:** _____

**Phone:** _____

Change 5: Effective January 1, 2016, the source has changed the name of the company from Duke Energy Indiana, Inc - Cayuga Generating Station to Duke Energy Indiana, LLC - Cayuga Generating Station.

The company name has been revised throughout the permit as follows:

Company Name: ~~Duke Energy Indiana, Inc - Cayuga Generating Station~~

**Duke Energy Indiana, LLC - Cayuga Generating Station**

**Other Changes**

Upon further review IDEM, OAQ has made the following changes to the Title V permit T165-33876-00001. (deleted language appears as ~~strikout~~ and the new language **bolded**):

**Change 1:** All Rule citations in the permit have been updated as follows;

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

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

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

**Change 2:** The Source Definition has been updated to conform with IDEM's standard language.

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

**This source consists of a power plant and a combustion turbine plant:**

**(a) Duke Energy Indiana, LLC - Cayuga Generating Station (ID # 165-00001), a power plant, is located at, SR 63, Cayuga, IN 47928; and**

**(b) Duke Energy Indiana, LLC - Cayuga Generating Station Unit 4 combustion turbine plant (ID # 165-00086), is located at SR 63, Cayuga, IN 47928.**

**IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source.**

**IDEM, OAQ finds that the two plants are part of the same major source. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.**

~~Duke Energy Indiana, Inc.'s Cayuga Generating Station, identified as 165-00001, is located on the same property as Duke Energy Indiana, Inc.'s Unit 4 combustion turbine plant identified as 165-00086. IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source. The term "major source" is defined at 326 IAC 2-7-1(22). In order for these two plants to be considered one major source, they must meet all three of the following criteria:~~

~~(1) the plants must be under common ownership or common control;~~

~~(2) the plants must belong to a single major industrial grouping or one must serve as a support facility for the other; and,~~

~~(3) the plants must be located on contiguous or adjacent properties.~~

~~The two plants are owned by Duke Energy Indiana, Inc. Since there is a common owner, the first element of the definition of major source is met.~~

~~The SIC Code Manual of 1987 sets out how to determine the proper SIC Code for each type of business, called establishments. The SIC Codes are divided up into eleven divisions, lettered A through K. Each division is broken down into separate major groups. Each major group has a distinct two-digit SIC Code. The two plants have the same two-digit SIC Code, 49, for Electric, Gas and Sanitary Services. Therefore the second element of the definition is met.~~

~~The two plants are located on the same piece of property in separate buildings. Since the plants are located on the same piece of property, they the third element of the definition. IDEM, OAQ finds that the two plants are part of the same major source. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.~~

**Change 3:** The descriptions of Boiler No. 1 and No.2 have been revised in Condition D.1.1 and D.2.1.

D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from **Boiler No. 1** ~~Boiler #1~~ shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This emissions limit is based on the historic Particulate Matter emission limit established under 326 IAC 6-2-3.

**********

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from **Boiler No. 2** ~~Boiler #2~~ shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This limit is based on the historic particulate matter emissions limit established under 326 IAC 6-2-3.

**Change 4:** Conditions D.1.9 & 2.9 - Maintenance of Continuous Emission Monitoring Equipment have been revised to remove the opacity language from the conditions.

D.1.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

**********

(d) Whenever a **NOx or SO2** continuous emission monitor ~~other than an opacity monitor~~ is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

**********

D.2.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

**********

(d) Whenever a **NOx or SO2** continuous emission monitor ~~other than an opacity monitor~~ is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

**********

**Change 5:** The typo in Condition D.5.6 - Reporting Requirements has been corrected in the permit accordingly.

D.5.6 Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

A quarterly summary of the information to document compliance with Conditions D.5.1(a) and D.5.1(d) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (3**0**) 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.

## Conclusion and Recommendation

The operation of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Permit Modification No. 165-36707-00001. The staff recommends to the Commissioner that this Part 70 Significant Permit Modification be approved.

## IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the 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) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

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

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**
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**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

February 5, 2016

Mr. Mack Sims
Duke Energy Indiana, LLC - Cayuga Generating Station
1000 E Main Street
Plainfield, IN 46168

Re: Public Notice
Duke Energy Indiana, LLC - Cayuga Generating Station
Permit Level: Title V - Significant Permit Modification
Permit Number: 165 - 36707 - 00001

Dear Mr. Sims:

Enclosed is a copy of your draft Title V - Significant Permit Modification, Technical Support Document, emission calculations, and the Public Notice which will be printed in your local newspaper.

The Office of Air Quality (OAQ) has prepared two versions of the Public Notice Document. The abbreviated version will be published in the newspaper, and the more detailed version will be made available on the IDEM's website and provided to interested parties. Both versions are included for your reference. The OAQ has requested that the Daily Clintonian in Clinton, Indiana publish the abbreviated version of the public notice no later than February 10, 2016. You will not be responsible for collecting any comments, nor are you responsible for having the notice published in the newspaper.

OAQ has submitted the draft permit package to the Vermillion County Public Library, P.O.Box 100, 385 E. Market St in Newport IN. 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 Josiah Balogun, 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 4-5257 or dial (317) 234-5257.

Sincerely,
Len Pogost

Len Pogost
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover letter 8/27/2015

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**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

**ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING**

February 5, 2016

Daily Clintonian
Attn: Classifieds
422 South Main Street
Clinton, Indiana 47842

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment for Cargill Dry Corn Ingredients, Vermillion County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than February 10, 2016.

Please send a notarized form, clippings showing the date of publication, and the billing to the Indiana Department of Environmental Management, Accounting, Room N1345, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

**To ensure proper payment, please reference account # 100174737.**

We are required by the Auditor's Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Len Pogost at 800-451-6027 and ask for extension 3-2803 or dial 317-233-2803.

Sincerely,

Len Pogost

Len Pogost
Permit Branch
Office of Air Quality

Permit Level: Title V - Significant Permit Modification
Permit Number: 165 - 36707 - 00001

Enclosure
PN Newspaper.dot 6/13/2013

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**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

February 5, 2016

To: Vermillion County Public Library P.O.Box 100, 385 E. Market St Newport IN

From: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

**Applicant Name: Duke Energy Indiana, LLC - Cayuga Generating Station**
**Permit Number: 165 - 36707 - 00001**

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
- Request to publish the Notice of 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 Smiddie-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.dot 8/27/2015

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**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

# Notice of Public Comment

**February 5, 2016**
**Duke Energy Indiana, LLC - Cayuga Generating Station**
**165 - 36707 - 00001**

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 been placed in the Legal Advertising section of your local newspaper. 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.*

Enclosure
PN AAA Cover.dot 8/27/2015

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**Michael R. Pence**
*Governor*

**Carol S. Comer**
*Commissioner*

# AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
# DRAFT INDIANA AIR PERMIT

February 5, 2016

A 30-day public comment period has been initiated for:

**Permit Number:** **165 - 36707 - 00001**
**Applicant Name:** **Duke Energy Indiana, LLC - Cayuga Generating Station**
**Location:** **Cayuga, Vermillion 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.dot 8/27/2015

# Mail Code 61-53

| | | | | |
|---|---|---|---|---|
| IDEM Staff | LPOGOST 2/5/2016<br>Duke Energy Indiana LLC - Cayuga Generating Station 165 - 36707 - 00001 draft | | | AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING |
| Name and address of Sender | ▶ | Indiana Department of Environmental Management<br>Office of Air Quality – Permits Branch<br>100 N. Senate<br>Indianapolis, IN 46204 | Type of Mail:<br>**CERTIFICATE OF MAILING ONLY** | |

| Line | Article Number | 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<br>Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Mack Sims Duke Energy Indiana LLC - Cayuga Generating Statio 1000 E Main Street Plainfield IN 46168 (Source CAATS) | | | | | | | | | |
| 2 | | William Luke Manager - Cayuga Generating Station Duke Energy Indiana LLC - Cayuga Generating Statio c/o M Sims 1000 E Main St Plainfield IN 46168 *(RO CAATS)* | | | | | | | | | |
| 3 | | Cayuga Town Council PO Box 33 Cayuga IN 47928 *(Local Official)* | | | | | | | | | |
| 4 | | Vermillion County Health Department 257 Walnut Street Clinton IN 47842-2342 *(Health Department)* | | | | | | | | | |
| 5 | | Vermillion County Public Library P.O.Box 100, 385 E. Market St Newport IN 47966-0100 *(Library)* | | | | | | | | | |
| 6 | | Vermillion County Commissioners P.O. Box 190 Newport IN 47966 *(Local Official)* | | | | | | | | | |
| 7 | | J.P. Roehm PO Box 303 Clinton IN 47842 *(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 mil 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 inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels. |

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