NOTICE OF 30-DAY PERIOD
FOR PUBLIC COMMENT

Preliminary Findings Regarding the Renewal of a Part 70 Operating Permit

for Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station
in Posey County

Part 70 Operating Permit Renewal No.: T129-40544-00010

The Indiana Department of Environmental Management (IDEM) has received an application from Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station, located at 8511 Welborn Road, Mount Vernon, IN 47620, for a renewal of its Part 70 Operating Permit issued on November 07, 2014. If approved by IDEM’s Office of Air Quality (OAQ), this renewal would allow Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station to continue to operate its existing source.

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

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

Alexandrian Public Library
115 W Fifth Street
Mount Vernon, IN 47620

and

IDEM Southwest Regional Office
114 South 7th Street
P.O. Box 128
Petersburg, IN 47567-0128

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

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

How can you participate in this process?

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

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the air pollution impact of this draft permit are received, with a request for a public hearing,
IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM’s mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number T129-40544-00010 in all correspondence.

Comments should be sent to:

Tamara Havics  
IDEM, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCM 1003  
Indianapolis, Indiana 46204-2251  
(800) 451-6027, ask for extension 2-8219  
Or dial directly: (317) 232-8219  
Fax: (317) 232-6749 attn: Tamara Havics  
E-mail: THavics@idem.in.gov

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

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

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM’s response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM’s decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, at the IDEM Regional Office 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 Tamara Havics of my staff at the above address.

[Signature]

Brian Williams, Section Chief  
Permits Branch  
Office of Air Quality
**Part 70 Operating Permit Renewal**

**OFFICE OF AIR QUALITY**

Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station  
8511 Welborn Road  
Mount Vernon, Indiana 47620

(herin 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.

<table>
<thead>
<tr>
<th>Operation Permit No.: T129-40544-00010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Master Agency Interest ID.: 11785</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Issued by:</th>
<th>Issuance Date:</th>
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<tr>
<td>Brian Williams Section Chief</td>
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<td>Permits Branch</td>
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<td>Office of Air Quality</td>
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<td>Expiration Date:</td>
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</tr>
</tbody>
</table>

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# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>SECTION A</th>
<th>SOURCE SUMMARY .................................................................................................................. 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>A.1</td>
<td>General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]</td>
</tr>
<tr>
<td>A.2</td>
<td>Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]</td>
</tr>
<tr>
<td>A.3</td>
<td>Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]</td>
</tr>
<tr>
<td>A.4</td>
<td>Insigificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]</td>
</tr>
<tr>
<td>A.5</td>
<td>Part 70 Permit Applicability [326 IAC 2-7-2]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SECTION B</th>
<th>GENERAL CONDITIONS .................................................................................................... 13</th>
</tr>
</thead>
<tbody>
<tr>
<td>B.1</td>
<td>Definitions [326 IAC 2-7-1]</td>
</tr>
<tr>
<td>B.2</td>
<td>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)]</td>
</tr>
<tr>
<td>B.3</td>
<td>Term of Conditions [326 IAC 2-1.1-9.5]</td>
</tr>
<tr>
<td>B.4</td>
<td>Enforceability [326 IAC 2-7-7] [IC 13-17-12]</td>
</tr>
<tr>
<td>B.5</td>
<td>Severability [326 IAC 2-7-5(5)]</td>
</tr>
<tr>
<td>B.6</td>
<td>Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]</td>
</tr>
<tr>
<td>B.7</td>
<td>Duty to Provide Information [326 IAC 2-7-5(6)(E)]</td>
</tr>
<tr>
<td>B.8</td>
<td>Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]</td>
</tr>
<tr>
<td>B.9</td>
<td>Annual Compliance Certification [326 IAC 2-7-6(5)]</td>
</tr>
<tr>
<td>B.10</td>
<td>Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]</td>
</tr>
<tr>
<td>B.11</td>
<td>Emergency Provisions [326 IAC 2-7-16]</td>
</tr>
<tr>
<td>B.12</td>
<td>Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]</td>
</tr>
<tr>
<td>B.13</td>
<td>Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]</td>
</tr>
<tr>
<td>B.14</td>
<td>Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]</td>
</tr>
<tr>
<td>B.15</td>
<td>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]</td>
</tr>
<tr>
<td>B.16</td>
<td>Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]</td>
</tr>
<tr>
<td>B.17</td>
<td>Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]</td>
</tr>
<tr>
<td>B.18</td>
<td>Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]</td>
</tr>
<tr>
<td>B.19</td>
<td>Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]</td>
</tr>
<tr>
<td>B.20</td>
<td>Source Modification Requirement [326 IAC 2-7-10.5]</td>
</tr>
<tr>
<td>B.21</td>
<td>Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]</td>
</tr>
<tr>
<td>B.22</td>
<td>Transfer of Ownership or Operational Control [326 IAC 2-7-11]</td>
</tr>
<tr>
<td>B.23</td>
<td>Annual Fee Payment [326 IAC 2-7-19][326 IAC 2-7-5][326 IAC 2-7-4(a)]</td>
</tr>
<tr>
<td>B.24</td>
<td>Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314][326 IAC 1-1-6]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SECTION C</th>
<th>SOURCE OPERATION CONDITIONS .................................................................................. 24</th>
</tr>
</thead>
<tbody>
<tr>
<td>C.1</td>
<td>Emission Limitations and Standards [326 IAC 2-7-5(1)] ............................................... 24</td>
</tr>
<tr>
<td>C.2</td>
<td>Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]</td>
</tr>
<tr>
<td>C.3</td>
<td>Opacity [326 IAC 5-1]</td>
</tr>
<tr>
<td>C.4</td>
<td>Open Burning [326 IAC 4-1][IC 13-17-9]</td>
</tr>
<tr>
<td>C.5</td>
<td>Incineration [326 IAC 4-2][326 IAC 9-1-2]</td>
</tr>
<tr>
<td>C.6</td>
<td>Fugitive Dust Emissions [326 IAC 6-4]</td>
</tr>
<tr>
<td>C.7</td>
<td>Stack Height [326 IAC 1-7]</td>
</tr>
<tr>
<td>C.8</td>
<td>Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]</td>
</tr>
<tr>
<td>C.9</td>
<td>Asbestos Abatement Projects [326 IAC 14-10][326 IAC 18] [40 CFR 61, Subpart M]</td>
</tr>
</tbody>
</table>

| Testing Requirements [326 IAC 2-7-6(1)] ...................................................... 26 |
|----------------|------------------------------------------------------------------------------------------------|
| C.9            | Performance Testing [326 IAC 3-6] |
Compliance Requirements [326 IAC 2-1.1-11] ........................................................................................................ 26
C.10 Compliance Requirements [326 IAC 2-1.1-11]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] ........................................... 26
C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]
[40 CFR 64][326 IAC 3-8]
C.12 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6] ............................................... 27
C.13 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
C.14 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]
C.15 Response to Excursions or Exceedances [40 CFR 64] [326 IAC 2-7-5]
[326 IAC 2-7-6]
C.16 Actions Related to Noncompliance Demonstrated by a Stack Test
[326 IAC 2-7-5][326 IAC 2-7-6]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] .......................... 30
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]
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]
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]

Stratospheric Ozone Protection .................................................................................................................. 34
C.20 Compliance with 40 CFR 82 and 326 IAC 22-1

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS .............................................................. 35

Emission Limitations and Standards [326 IAC 2-7-5(1)] ........................................................................ 35
D.1.1 Sulfur Dioxide (SO2) Emission Limitations [326 IAC 7-1.1-2]
D.1.2 Sulfur Dioxide (SO2) Commissioner's Order [IC 13-14-2-1(b)][IC 13-14-2-7(1)][326
IAC 1-3-4(b)(1)(A)][326 IAC 2-7-1(6)]
D.1.3 Consent Decree [Civil Action No. IP99-1692 C-M/F]
D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Determination Requirements [326 IAC 2-7-5(1)] .............................................................. 36
D.1.5 Operation of Fabric Filter [326 IAC 2-7-6(6)]
D.1.6 Flue Gas Desulfurization (FGD) System [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]
D.1.7 Continuous Emission Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)][40 CFR 60]
D.1.8 Particulate Matter (PM) Continuous Emission Monitoring System (CEMS) [326 IAC
3-5-1(c)][326 IAC 2-7-5(3)(A)(iii)][40 CFR 60]
D.1.9 Sulfur Dioxide Emissions [326 IAC 3-5][326 IAC 7-2-1]
D.1.10 Testing Requirements [326 IAC 2-1.1-11]
D.1.11 Sorbent Reagent Injection Flow Rate Requirement

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] ........................................... 37
D.1.12 PM Continuous Emissions Monitoring (CEMS) Equipment Downtime
D.1.13 SO2 Continuous Emissions Monitoring (CEMS) Equipment Downtime
D.1.14 Sorbent Injection System Monitoring Requirements [40 CFR 64]

Record Keeping and Reporting Requirements
[326 IAC 2-7-5(3)][326 IAC 2-7-19][326 IAC 3-5] .................................................................................. 38
D.1.15 Record Keeping Requirement
D.1.16 Reporting Requirements

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS .............................................................. 41

Emission Limitations and Standards [326 IAC 2-7-5(1)] ........................................................................ 41
D.2.1 PSD BACT [326 IAC 2-2-3]
D.2.2 SO2 PSD BACT Requirements [326 IAC 2-2-3]
D.2.3 Sulfur Dioxide (SO₂) Commissioner's Order [IC 13-14-2-1(b)] [IC 13-14-2-7(1)] [326 IAC 1-3-4(b)(1)(A)] [326 IAC 2-7-1(6)]
D.2.4 Sulfur Dioxide (SO₂) Emission Limitations [326 IAC 7-1.1-2]
D.2.5 Consent Decree [Civil Action No. IP99-1692 C-M/F]
D.2.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Determination Requirements [326 IAC 2-7-5(1)] ............................................................... 43
D.2.7 Operation of Electrostatic Precipitator
D.2.8 Flue Gas Desulfurization (FGD) System
D.2.9 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)] [40 CFR 60]
D.2.10 Particulate Matter (PM) and Hg Continuous Emission Monitoring System (CEMS) [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
D.2.11 Particulate (PM) and NOx Emissions [326 IAC 3-5]
D.2.12 Sulfur Dioxide Emissions [326 IAC 3-5][326 IAC 7-2-1]
D.2.13 Testing Requirements [326 IAC 2-1.1-11]
D.2.14 Sorbent Reagent Injection Flow Rate Requirement

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)] ........................................... 44
D.2.15 PM Monitoring System Downtime
D.2.16 SO₂ Continuous Emissions Monitoring (CEMS) Equipment Downtime
D.2.17 NOx Monitoring System Downtime
D.2.18 Sorbent Injection System Monitoring Requirements [40 CFR 64]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19][326 IAC 3-5] ................................................................. 45
D.2.19 Record Keeping Requirements
D.2.20 Reporting Requirements

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS ................................................................. 48

Emission Limitations and Standards [326 IAC 2-7-5(1)] ................................................................. 48
D.3.1 PSD Minor Limits [326 IAC 2-2]
D.3.2 Sulfur Dioxide (SO₂) [326 IAC 7-1.1] [326 IAC 7-2-1]
D.3.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Determination Requirements [326 IAC 2-7-5(1)] ............................................................. 49
D.3.4 Parametric Emission Monitoring System (PEMS) for NOx [326 IAC 3-5]
D.3.5 Sulfur Dioxide Emissions and Sulfur Content

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)] ........................................... 50
D.3.6 Visible Emissions Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] .......................... 50
D.3.7 Record Keeping Requirement
D.3.8 Reporting Requirements

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS ................................................................. 52

Emission Limitations and Standards [326 IAC 2-7-5(1)] ................................................................. 52
D.4.1 PM10 PSD BACT [326 IAC 2-2-3]
D.4.2 NOx PSD BACT [326 IAC 2-2-3]
D.4.3 CO PSD BACT [326 IAC 2-2-3]
D.4.4 326 IAC 2-2-3 (PSD Requirements) Startup and Shutdown Limitations for Combustion Turbines
D.4.5 Hazardous Air Pollutants (HAP) Limitations [326 IAC 2-4.1]
D.4.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Determination Requirements [326 IAC 2-7-5(1)] ............................................................. 53
D.4.7 Continuous Emission Monitoring [326 IAC 2-7-6(1),(6)][326 IAC 2-2] [326 IAC 3-5]
Compliance Monitoring Requirements [326 IAC 2-7-5(1)] .......................................................... 54
D.4.8 NOx or CO Continuous Emissions Monitoring (CEMS) Equipment Downtime

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] ............... 55
D.4.9 Record Keeping Requirement
D.4.10 Reporting Requirements

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS .......................................................... 57

Emission Limitations and Standards [326 IAC 2-7-5(1)] ............................................................ 57
D.5.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]
D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]
D.5.3 Particulate Control

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] ......................... 58
D.5.4 Visible Emission Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] ............... 59
D.5.5 Record Keeping Requirement

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS .......................................................... 60

Emission Limitations and Standards [326 IAC 2-7-5(1)] ............................................................ 60
D.6.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]
D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] ......................... 61
D.6.3 Visible Emission Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] ............... 61
D.6.4 Record Keeping Requirement

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS .......................................................... 62

Emission Limitations and Standards [326 IAC 2-7-5(1)] ............................................................ 62
D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]
D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] ......................... 63
D.7.3 Visible Emission Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] ............... 63
D.7.4 Record Keeping Requirement

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS .......................................................... 64

Emission Limitations and Standards [326 IAC 2-7-5(1)] ............................................................ 64
D.8.1 Volatile Organic Compound (VOC) [326 IAC 8-3-2]
D.8.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]
D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] ............... 65
D.8.4 Record Keeping Requirement

SECTION E.1 NSPS ......................................................................................................................... 66

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] .................... 66
E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1]
[40 CFR Part 60, Subpart A]
E.1.2 Fossil - Fuel Steam Generators for Which Construction is Commenced After August 17, 1971 NSPS [326 IAC 12] [40 CFR Part 60, Subpart D]
SECTION E.2 NSPS ................................................................................................................................ 67

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]................. 67
E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.2.2 Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

SECTION E.3 NSPS ................................................................................................................................ 68

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]................. 68
E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.3.2 Stationary Gas Turbines NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

SECTION E.4 NESHA P ........................................................................................................................... 69

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]................................................................. 69
E.4.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]
E.4.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

SECTION E.6 NESHA P ........................................................................................................................... 71

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]................................................................. 71
E.6.2 Coal and Oil Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

SECTION E.7 Acid Rain Program .................................................................................................................. 73

Acid Rain Program ............................................................................................................................... 74
E.7.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]
E.7.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

SECTION F TR NOx Annual Trading Program, TR NOx Ozone Season Trading Program, and TR SO2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)...................................................... 75
F.1 Designated representative requirements
F.2 Emissions monitoring, reporting, and recordkeeping requirements
F.3 NOx Annual Emissions Requirements
F.4 NOx Ozone Season Requirements
F.5 SO2 Emissions Requirements
F.6 Title V Permit Revision Requirements
F.7 Additional recordkeeping and reporting requirements
F.8 Liability
F.9 Effect on other authorities
F.10 Description of TR Monitoring Provisions

CERTIFICATION ........................................................................................................................................ 89

EMERGENCY OCCURRENCE REPORT ................................................................................................. 90
Part 70 Quarterly Report .......................................................................................................................... 92
Part 70 Quarterly Report .......................................................................................................................... 93
Part 70 Quarterly Report ........................................................................................................................................... 94
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT ................................................................. 95

Attachment A: Fugitive Dust Plan

Attachment B: NSPS for Fossil-Fuel-Fired Steam Generator for Which Construction is Commenced After August 17, 1971, 40 CFR 60, Subpart D

Attachment C: NSPS for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 40 CFR 60, Subpart Da

Attachment D: NSPS for Stationary Gas Turbines, 40 CFR 60, Subpart GG

Attachment E: NESHAP for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ

Attachment F: NESHAP for Coal and Oil Fired Electric Utility Steam Generating Units, 40 CFR Part 63, Subpart UUUUU
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.4 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:               | 8511 Welborn Road, Mount Vernon, Indiana 47620 |
| General Source Phone Number:  | 812-491-4562                                      |
| SIC Code:                     | 4911 and 4922 [Electric Services and Natural Gas Transmission] |
| County Location:              | Posey                                              |
| Source Location Status:       | Attainment for all criteria pollutants             |
| Source Status:                | Part 70 Operating Permit Program                   |
|                               | Major Source, under PSD Rules                     |
|                               | Major Source, Section 112 of the Clean Air Act     |
|                               | 1 of 28 Source Categories                         |

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

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

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low -NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]
(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOx) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

1. One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.
2. One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.
3. An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.
4. Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers.

(f) A lime storage and handling system with maximum loading of 42000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

1. One (1) railcar and truck unloading station, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.
2. Two (2) storage silos, each with a maximum capacity of 1300 tons, each with a fabric filter to recover the pneumatically conveyed material.
3. One (1) storage silo, with a storage capacity of 2600 tons, each with a fabric filter to recover the pneumatically conveyed material.
4. Three (3) usage bins, each with a storage capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(g) A soda ash storage and handling system with maximum loading of 6000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

1. One (1) railcar and truck unloading station, with particulate matter emissions controlled by enclosure, with pneumatic conveyance to the storage silos, with a
(2) Two (2) storage silos, each with a maximum capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(h) The wet fly and bottom ash handling system was installed and expanded with start-up dates of 1979 (installed with Boiler Unit No. 1) and 1985 (installed with Boiler Unit No. 2). The dry fly ash (DFA) system was subsequently added to accommodate the option for product recovery of DFA material through a separate storage, handling, and bargeing operation to an off-site location. The DFA handling system interfaces with the existing wet ash system at the Hydroveyor. (Hydroveyor No. 1 for A. B. Brown No. 1 and Hydroveyor No. 2 for A. B. Brown No. 2). Each existing Hydroveyor is a water-exhauster powered-vacuum system that conveys ash in a dry state up to the exhauster where it then converts to slurry form and then flows to an ash separator where the conveying air is vented off and the slurry flows by gravity to the existing ash pond. The existing handling system was modified to incorporate the all-dry filter/seperator design (Filter/Separator No. 1 for A. B. Brown No. 1 and Filter/Separator No. 2 for A. B. Brown No. 2). Each Hydroveyor remains in-service and each filter/seperator, with bypasses, intercept the fly ash for transport to the storage silo. Each existing Hydroveyor continues to discharge water to the existing ash pond and the existing fly ash system continues to route fly ash slurry flows to the ash pond for maintenance or product quality episodes. The filter/separators discharge to the Intermediate Silo (storage capacity of 2500 tons). The Intermediate Silo is equipped with a bin vent filter and truck unloading station. The truck unloading station receives ash from other Vectren operations for transfer to the Barge Loader. The truck unloading station is equipped with two truck bays to receive ash product. The transport and handling system that extends from the Intermediate Silo and through to the Barge Loader is a common (single) system with a design capacity of 700 ton/hr. The Intermediate Silo discharge is fitted with a feeder to load the dry conveyor (belt) for transport to the Barge Loading Transfer Tower. The Barge Loading Transfer Tower conveys DFA, via air-slide, to the barge. The DFA product enters the barge through a telescopic loading nozzle fitted with a dust control ring to control fugitive dust. The Barge Loader conveyor is equipped with a fabric filter dust collector which vents to the atmosphere.

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, with wet sludge conveyed to haul trucks.

A.3 Specifically Regulated Insignificant Activities

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

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

(b) Two (2) distillate oil-fired emergency generators rated 398 bhp each, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, these are affected facilities.]

(c) One (1) distillate oil-fired fire pump rated 200 bhp, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, this is an affected facility]

(d) Coal bunker and coal scale exhausts and associated dust collector vents.
(e) The following equipment performing maintenance activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

A.4 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:

(a) Combustion source flame safety purging on startup.

(b) A gasoline fuel transfer and dispensing operation handling less than or equal to 1,300 gallons per day, such as filling of tanks, locomotives, automobiles, having a storage capacity less than or equal to 10,500 gallons.

(c) A petroleum fuel, other than gasoline, dispensing facility having a storage capacity less than or equal to 10,500 gallons, and dispensing less than or equal to 230,000 gallons per month.

(d) The following VOC and HAP storage containers:
   (1) Storage tanks with capacity less than or equal to 1,000 gallons and annual throughput less than 12,000 gallons.
   (2) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids.

(e) Machining where an aqueous cutting coolant continuously floods the machining interface.

(f) Solvent recycling systems with batch capacity less than or equal to 100 gallons.

(g) Activities associated with the transportation and treatment of sanitary sewage, provided discharge to the treatment plant is under the control of the owner/operator, that is, an on-site sewage treatment facility.

(h) Noncontact cooling tower systems with either of the following: Forced and induced draft cooling tower system not regulated under a NESHAP.

(i) Replacement or repair of electrostatic precipitators, bags in baghouses and filters in other air filtration equipment.

(j) Heat exchanger cleaning and repair.

(k) Stockpiled soils from soil remediation activities that are covered and waiting transportation for disposal.

(l) Paved and unpaved roads and parking lots with public access.

(m) Asbestos abatement projects.

(n) Purging of gas lines and vessels that is related to routing maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(o) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.
(p) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(q) On-site fire and emergency response training approved by the department.

(r) Vents from ash transport systems not operated at positive pressure.

(s) A laboratory as defined in 326 IAC 2-7(21)(D).

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

(1) Fuel Oil Storage Tank #1

(2) Fuel Oil Storage Tank #2

(3) Boiler Chemical cleaning waste evaporation

(4) Ash pond and ash pond maintenance, with water cover, vegetation, wind barriers, commercial dust control product, or other means sufficient to prevent ash re-entrainment.

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, T 129-40544-00010, 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 5
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 (PMP) 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 or Southwest Regional Office 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
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304.

(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 T129-40544-00010 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

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

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

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

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

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

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).
(c) **Emission Trades [326 IAC 2-7-20(c)]**
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) **Alternative Operating Scenarios [326 IAC 2-7-20(d)]**
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.

(e) **Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.**

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

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

**B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]**

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee’s right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

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

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

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

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

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

**B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]**

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

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:
Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

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

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

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

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

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

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

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

### Entire Source

<table>
<thead>
<tr>
<th>Emission Limitations and Standards  [326 IAC 2-7-5(1)]</th>
</tr>
</thead>
<tbody>
<tr>
<td>C.1   Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>C.2   Opacity [326 IAC 5-1]</td>
</tr>
<tr>
<td>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:</td>
</tr>
<tr>
<td>(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.</td>
</tr>
<tr>
<td>(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.</td>
</tr>
<tr>
<td>C.3   Open Burning [326 IAC 4-1] [IC 13-17-9]</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>C.4   Incineration [326 IAC 4-2] [326 IAC 9-1-2]</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>C.5   Fugitive Dust Emissions [326 IAC 6-4]</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>C.6   Stack Height [326 IAC 1-7]</td>
</tr>
<tr>
<td>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.</td>
</tr>
<tr>
<td>C.7   Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]</td>
</tr>
<tr>
<td>Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the attached plan as in Attachment A. The provisions of 326 IAC 6-5 are not federally enforceable.</td>
</tr>
</tbody>
</table>
C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

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

2. If there is a change in the following:
   - Asbestos removal or demolition start date;
   - Removal or demolition contractor;
   - Waste disposal site.

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

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

All required notifications shall be submitted to:

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

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

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

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).
(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

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(11)] [40 CFR 68]
If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.15 Response to Excursions or Exceedances [40 CFR 64] [326 IAC 2-7-5] [326 IAC 2-7-6]
(I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

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

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

1. initial inspection and evaluation;
2. recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or
3. any necessary follow-up actions to return operation to normal or usual manner of operation.

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

1. monitoring results;
2. review of operation and maintenance procedures and records; and/or
3. inspection of the control device, associated capture system, and the process.

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

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

(II) CAM Response to excursions or exceedances.

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

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

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

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

(d) Elements of a QIP:
   The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 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)(c) 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.
The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

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.

(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).

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(yy)) 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 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.
SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUU, this is an affected facility]

Insignificant Activities

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

(3) Boiler Chemical cleaning waste evaporation

(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 Sulfur Dioxide (SO2) Emission Limitations [326 IAC 7-1.1-2(a)(1)]

Pursuant to 326 IAC 7-1.1-2(a)(1) (Sulfur Dioxide Emission Limitations), the SO2 emissions from Boiler No. 1 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

D.1.2 Sulfur Dioxide (SO2) Commissioner’s Order [IC 13-14-2-1(b)][IC 13-14-2-7(1)][326 IAC 1-3-4(b)(1)(A)][326 IAC 2-7-1(6)]

(a) When Boiler Unit No. 1 is operating alone, the unit shall not exceed SO2 emission limitations and emission rates as follows:

(1) 2152.2 lb/hr, one (1) hour average or emission rate of 0.855 lb/MMBtu, one (1) hour average; and

(2) 1831.6 lb/hr, twenty-four (24) hour rolling average or emission rate of 0.727 lb/MMBtu, twenty-four (24) hour rolling average.

(b) When both Boiler Unit No. 1 and Boiler Unit No. 2* are in operation, both units shall not exceed combined SO2 emission limitations and emission rates as follows:

(1) 2152.2 lb/hr, one (1) hour average or emission rate of 0.426 lb/MMBtu, one (1) hour average; and

(2) 1831.6 lb/hr, twenty-four (24) hour rolling average or emission rate of 0.363
lb/MMBtu, twenty-four (24) hour rolling average.

*Pursuant to PSD (65) 1355 issued on February 22, 1979, Boiler Unit No. 2 shall not exceed an SO₂ emission limitation of 0.69 lb/MMBtu, thirty (30) day rolling average. The SO₂ emission limitation applies to Boiler Unit No. 2 whenever Boiler Unit No. 2 is operating; this includes when Boiler Unit No. 2 is operating alone and when both Boiler Unit No. 1 and Boiler Unit No. 2 are in operation.

(c) The Petitioner shall comply with the SO₂ emission limitations and emission rates beginning April 19, 2016.

(d) As required by 326 IAC 2-7-2(d)(1) and 326 IAC 2-7-5, the Petitioner shall apply to incorporate Order requirements, including reporting and recordkeeping requirements and methods to determine compliance, into its Part 70 Operating Permit within ninety (90) days of U.S. EPA approval of the Commissioner's Order into the Indiana SIP.

(e) This Order shall apply to and be binding upon the Petitioner, its successors and assigns. No change in ownership, corporate, or partnership status of the Petitioner shall in any way alter its status or responsibilities under this Order.

(f) The requirements of this Order supersede any less stringent requirements applicable to the Petitioner.

D.1.3 Consent Decree [Civil Action No. IP99-1692 C-M/F]

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, effective December 16, 2015:

The Permittee shall install a sorbent injection system at Boiler Unit No. 1 to mitigate sulfur trioxide (SO₃) and resulting sulfuric acid (H₂SO₄) emissions from the Boiler Unit No. 1, no later than December 31, 2015. Thereafter, the Permittee shall continuously operate the sorbent injection system at Boiler Unit No. 1 on a permanent basis at all times the Boiler Unit No. 1 is in operation, and achieve and maintain a H₂SO₄ emission limit of 0.008 lb/MMBtu.

D.1.4 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for this facility and its control devices. 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.1.5 Operation of Fabric Filter [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the fabric filter for Boiler Unit No. 1 shall be operated at all times that the Boiler Unit No. 1 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels.

D.1.6 Flue Gas Desulfurization (FGD) System [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system for Boiler Unit No. 1 shall be operated as needed to maintain compliance with applicable SO₂ emission limits.

D.1.7 Continuous Emission Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1,6)][40 CFR 60]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 40 CFR 60.45, continuous emission monitoring systems for Boiler Unit No. 1 shall be calibrated, maintained, and operated for measuring SO₂, NOₓ, and either CO₂ or O₂ which meet all applicable performance specifications of 326 IAC 3-5-2 and 40 CFR 60.45.
(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) 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, 40 CFR 75 and 40 CFR 96.

D.1.8 Particulate Matter (PM) Continuous Emission Monitoring System (CEMS) [326 IAC 3-5-1(c)] [326 IAC 2-7-5(3)(A)(iii)][40 CFR 60]

(a) Pursuant to 326 IAC 3-5-1(c), the Permittee shall install, certify, maintain, and operate CEMS measuring PM emissions discharged from the Boiler Unit No. 1 stack to the atmosphere.

(b) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and Procedure 2 of 40 CFR 60, Appendix F.

D.1.9 Sulfur Dioxide Emissions [326 IAC 3-5][326 IAC 7-2-1]

(a) Compliance with the applicable limitation in Condition D.1.1 shall be determined based on a thirty (30) day rolling weighted average emissions rates using SO2 continuous monitoring system outlet data. The diluent cap methodology under 40 CFR 75 may be used to calculate emissions in lbs/MMBtu.

(b) Compliance with the applicable particulate emission limitations in Condition D.1.2 shall be determined based on the hourly arithmetic average and twenty-four (24) hour rolling average emissions rates using SO2 continuous monitoring system outlet data.

D.1.10 Testing Requirements [326 IAC 2-1.1-11]

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, effective December 16, 2015, and in order to demonstrate compliance with Condition D.1.3, the Permittee shall perform annual H2SO4 testing of Boiler Unit No. 1 utilizing methods approved by the commissioner. 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 obligation with regard to the performance testing required by this condition.

D.1.11 Sorbent Reagent Injection Flow Rate Requirement

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, and in order to assure compliance with Condition D.1.3, the Permittee shall maintain the reagent injection rate utilized during the most recent compliance stack test and the corresponding performance curve for Boiler Unit No. 1.

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

D.1.12 PM Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a PM continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a PM continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup PM CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary PM CEMS, the Permittee shall comply with the following:
(1) The Fabric Filter shall be monitored once per day when the unit is in operation by monitoring and recording the number of FF compartments in service.

   (A) The number of Fabric Filter compartments in service shall be maintained at a level consistent with the air-to-cloth ratio operating condition of two compartments out of service or greater.

   (B) Failure to maintain the number of operating compartments in service at a level equal to or greater with the air-to-cloth ratio operating condition will not be considered a deviation from this permit; rather, failure to take response steps to remedy the situation shall be considered a deviation from this permit.

   (c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction.

D.1.13 SO2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a SO2 continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) At any time the flue gas desulfurization (FGD) system is operating, if the SO2 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 boiler load, recirculation pH, liquor feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the flue gas desulfurization (FGD) continues in a manner typical for the boiler load and sulfur content of the coal fired. Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a SO2 CEMS is online.

D.1.14 Sorbent Injection System Monitoring Requirements [40 CFR 64]

The Permittee shall continuously monitor and record the sorbent injection flow rate of the sorbent injection system used in conjunction with Boiler Unit No. 1 when Boiler Unit No. 1 is in operation. When for any one reading, the sorbent injection flow rate is less than the minimum sorbent injection flow rate established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances.

The instruments used for determining the flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated at least once a year.

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

D.1.15 Record Keeping Requirement

(a) To document the compliance status with Conditions D.1.1, D.1.2, D.1.7, and D.1.8, the Permittee shall record the output of the PM, SO2, NOx, and either CO2 or O2 continuous monitoring systems and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7. Records shall be complete and sufficient to establish compliance with the limits as required in Conditions D.1.1 and to show compliance with the Commissioner's Order in Condition D.1.2.
In the event that a breakdown of the continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

To document the compliance status with Conditions D.1.3 and D.1.11 and pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, the Permittee shall maintain the following records:

1. Daily log of the reagent injection rates maintained at the Boiler Unit No. 1, including the date
2. Average daily unit load (MWg)
3. Operating hours for each day
4. Reagent injection flow rate (gallons per minute and tons per hour)
5. Reagent density (if injecting liquid reagent)

The Permittee shall maintain records of the number of Fabric Filter compartments in service when the PM CEMs is malfunctioning or down for maintenance, repair or adjustments for 24 hours or more, in accordance with Condition D.1.12. The Permittee shall include in its record when readings are not taken and the reason for lack of readings (e.g., the Fabric Filter and associated units did not operate).

The Permittee shall maintain records of the boiler load, recirculation pH, liquor feed rate, and number of recirculation pumps in service when the SO2 CEMs is malfunctioning or down for maintenance, repair or adjustments for 24 hours or more, in accordance with Condition D.1.13. The Permittee shall include in its record when readings are not taken and the reason for lack of readings (e.g., the FGD and associated units did not operate).

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

**D.1.16 Reporting Requirements**

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

1. Owners or operators of emissions units required to conduct a:
   
   (A) cylinder gas audit;
   (B) relative accuracy test audit; or
   (C) continuous opacity monitor calibration error audit;

   on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits. Reports shall be submitted within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

   (2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

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

1. date of downtime;
(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

(c) A quarterly summary of the thirty (30) day rolling weighted average emissions rate in pound per million Btu to document the compliance status with Condition D.1.1 and 326 IAC 3-5 and a quarterly summary of the daily maximum twenty four (24) hour rolling average emission rates to document the compliance status with Condition D.1.2 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(d) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low-NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

Insignificant Activities:

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

(3) Boiler Chemical cleaning waste evaporation

(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 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD BACT) and PSD (65) 1355 issued on February 22, 1979, the emission rates from Boiler Unit No.2 shall not exceed the following:

(a) Particulate matter (PM) - 0.03 pounds per million Btu (MMBtu) of energy input.
(b) Sulfur dioxide - 0.69 pounds per million Btu (MMBtu) of energy input.
(c) Nitrogen oxides - 0.6 pounds per million Btu (MMBtu) of energy input.
(d) The stack gas particulate emissions shall be controlled by an electrostatic precipitator having a minimum collection efficiency of 99.6% when burning coal with a maximum ash content of 10%, a minimum sulfur content of 2.5% and a minimum heat content of 11,000 Btu's per pound.

D.2.2 SO2 PSD BACT Requirements [326 IAC 2-2-3]

Pursuant to PSD (65) 1355 issued on February 22, 1979, "Best Available Control Technology" (BACT) emission controls shall be used for Boiler Unit No. 2 as follows:

(a) Sulfur dioxide shall be controlled by a scrubber having a minimum control efficiency of 90.0%.
D.2.3 Sulfur Dioxide (SO2) Commissioner’s Order [IC 13-14-2-1(b)][IC 13-14-2-7(1)][326 IAC 1-3-4(b)(1)(A)][326 IAC 2-7-1(6)]

(a) When both Boiler Unit No. 1 and Boiler Unit No. 2* are in operation, both units shall not exceed combined SO2 emission limitations and emission rates as follows:

1. 2152.2 lb/hr, one (1) hour average or emission rate of 0.426 lb/MMBtu, one (1) hour average; and

2. 1831.6 lb/hr, twenty-four (24) hour rolling average or emission rate of 0.363 lb/MMBtu, twenty-four (24) hour rolling average.

(b) When Boiler Unit No. 2* is operating alone, the unit shall not exceed SO2 emission limitations and emission rates as follows:

1. 1745.7 lb/hr, one (1) hour average or emission rate of 0.690 lb/MMBtu, one (1) hour average; and

2. 1485.59 lb/hr, twenty-four (24) hour rolling average or emission rate of 0.588 lb/MMBtu, twenty four (24) rolling average.

*Pursuant to PSD (65) 1355 issued on February 22, 1979, Boiler Unit No. 2 shall not exceed an SO2 emission limitation of 0.69 lb/MMBtu, thirty (30) day rolling average. The SO2 emission limitation applies to Boiler Unit No. 2 whenever Boiler Unit No. 2 is operating; this includes when Boiler Unit No. 2 is operating alone and when both Boiler Unit No. 1 and Boiler Unit No. 2 are in operation.

(c) The Petitioner shall comply with the SO2 emission limitations and emission rates beginning April 19, 2016.

(d) As required by 326 IAC 2-7-2(d)(1) and 326 IAC 2-7-5, the Petitioner shall apply to incorporate Order requirements, including reporting and recordkeeping requirements and methods to determine compliance, into its Part 70 Operating Permit within ninety (90) days of U.S. EPA approval of the Commissioner's Order into the Indiana SIP.

(e) This Order shall apply to and be binding upon the Petitioner, its successors and assigns. No change in ownership, corporate, or partnership status of the Petitioner shall in any way alter its status or responsibilities under this Order.

(f) The requirements of this Order supersede any less stringent requirements applicable to the Petitioner.

D.2.4 Sulfur Dioxide (SO2) Emission Limitations [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2(a)(1) (Sulfur Dioxide Emission Limitations), the SO2 emissions from Boiler Unit No. 2 shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

D.2.5 Consent Decree [Civil Action No. IP99-1692 C-M/F]

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, effective December 16, 2015:

The Permittee shall install a sorbent injection system at Boiler Unit No. 2 to mitigate sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions from the Boiler Unit No. 2, no later than December 31, 2015. Thereafter, the Permittee shall continuously operate sorbent injection system at Unit No. 2 on a permanent basis at all times the Boiler Unit No. 2 is in operation, and achieve and maintain a H2SO4 emission limit of 0.010 lb/MMBtu.
D.2.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for this facility and its control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

D.2.7 Operation of Electrostatic Precipitator

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) for Boiler Unit No. 2 shall be in operation at all times that the Boiler Unit No. 2 is in operation and combusting any amount of solid fuel or any combination of solid fuel and other fuels, except during periods of startup, shutdown, or emergency as described in Section B - Emergency Provisions.

D.2.8 Flue Gas Desulfurization (FGD) System

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system for Boiler Unit No. 2 shall be operated as needed to maintain compliance with all applicable SO2 emission limits.

D.2.9 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)] [40 CFR 60]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 40 CFR 60.45, continuous emission monitoring systems for Boiler Unit No. 2 shall be calibrated, maintained, and operated for measuring SO2, NOx, and either CO2 or O2 which meet all applicable performance specifications of 326 IAC 3-5-2 and 40 CFR 60.45.

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

(c) 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, 40 CFR 75 and 40 CFR 96.

D.2.10 Particulate Matter (PM) and Hg Continuous Emission Monitoring System (CEMS) [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

(a) Pursuant to 326 IAC 3-5-1, the Permittee shall install, certify, maintain, and operate CEMS measuring PM and Hg emissions discharged from Boiler Unit No. 2 stack to the atmosphere.

(b) The PM CEMS shall be installed, certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and Procedure 2 of 40 CFR 60, Appendix F.

D.2.11 Particulate (PM) and NOx Emissions [326 IAC 3-5]

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

(b) Compliance with the applicable limitation in Condition D.2.1(c) shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions concentrations using continuous monitoring system outlet data.

D.2.12 Sulfur Dioxide Emissions [326 IAC 3-5][326 IAC 7-2-1]

(a) Compliance with the applicable particulate emission limitations in Conditions D.2.1(b) and D.2.4 shall be determined based on thirty (30) day rolling weighted average
emissions rates using SO2 continuous monitoring system outlet data. The diluent cap methodology under 40 CFR 75 may be used to calculate emissions in lbs/MMBtu.

(b) Compliance with the applicable SO2 limitations in Condition D.2.3 shall be determined based on the hourly arithmetic average and twenty-four (24) hour rolling average emissions concentrations using SO2 continuous monitoring system outlet data.

D.2.13 Testing Requirements [326 IAC 2-1.1-11]

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, effective December 16, 2015, and in order to demonstrate compliance with Condition D.2.5, the Permittee shall perform annual H2SO4 testing of Boiler Unit No. 2 utilizing methods approved by the commissioner. 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 obligation with regard to the performance testing required by this condition.

D.2.14 Sorbent Reagent Injection Flow Rate Requirement

Pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, and in order to assure compliance with Condition D.2.5, the Permittee shall maintain reagent injection rate utilized during the most recent compliance stack test and the corresponding performance curve for the Boiler Unit No. 2.

D.2.15 PM Monitoring System Downtime

(a) In the event that a breakdown of a PM continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a PM continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup PM CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary PM CEMS, the Permittee shall comply with the following:

(1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Boiler Unit 2 is in operation by measuring and recording the following:

(A) The primary and secondary currents of the T-R sets;

(B) The primary and secondary voltages of the T-R sets; and

(C) The daily number of T-R sets in service.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a PM CEMS is online.

D.2.16 SO2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a SO2 continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) At any time the flue gas desulfurization (FGD) system is operating, if the SO2 continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or
repairs for a period of twenty-four (24) hours or more and a backup SO2 CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary PM SO2, the Permittee shall comply with the following:

(1) At any time the flue gas desulfurization (FGD) system is operating, the Permittee shall monitor and record boiler load, recirculation pH, liquor feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the flue gas desulfurization (FGD) continues in a manner typical for the boiler load and sulfur content of the coal fired. Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a SO2 CEMS is online.

D.2.17 NOx Monitoring System Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall monitor the catalyst bed inlet temperature used in conjunction with the Boiler Unit No. 2 with a continuous temperature monitoring system no less often than once per four (4) hours. When for any one reading, the catalyst bed inlet temperature is below the minimum temperature, the Permittee shall take a reasonable response. The minimum temperature for this catalyst bed inlet is 380°F, unless a new minimum temperature is determined during the most recent valid compliant 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 temperature reading that is below the minimum temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

D.2.18 Sorbent Injection System Monitoring Requirements [40 CFR 64]

The Permittee shall continuously monitor and record the sorbent injection flow rate of the sorbent injection system used in conjunction with Boiler Unit No. 2 when Boiler Unit No. 2 is in operation. When for any one reading, the sorbent injection flow rate is less than the minimum sorbent injection flow rate established during the latest stack test, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances.

The instruments used for determining the flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated at least once a year.

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

D.2.19 Record Keeping Requirements

(a) To document the compliance status with Conditions D.2.1, D.2.3, D.2.4, D.2.9, and D.2.10, the Permittee shall record the output of the PM, SO2, NOx, and either CO2 or O2 continuous monitoring systems and shall perform the required record keeping pursuant to 326 IAC 3-5-6, 326 IAC 3-5-7, and 326 IAC 2-2. Records shall be complete and sufficient to establish compliance with the limits as required in Conditions D.2.1 and D.2.4
and to show compliance with the Commissioner's Order in Condition D.2.3.

(b) In the event that a breakdown of the continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) The Permittee shall maintain records of (1) through (3) below, when the PM CEMs is malfunctioning or down for maintenance, repair or adjustments for 24 hours or more, the Permittee shall include in its record when readings are not taken and the reason for lack of readings (e.g., the ESP and associated units did not operate).

(1) The primary and secondary currents of the T-R sets;

(2) The primary and secondary voltages of the T-R sets; and

(3) The daily number of T-R sets in service.

(d) To document the compliance status with Condition D.2.14 and pursuant to Consent Decree: Civil Action No. IP99-1692 C-M/F, effective June 6, 2003 and Joint Stipulation to Modify Consent Decree, the Permittee shall maintain the following records:

(1) Daily log of the reagent injection rates maintained at the Boiler Unit No. 2, including the date

(2) Average daily unit load (MWg)

(3) Operating hours for each day

(4) Reagent injection flow rate (gallons per minute and tons per hour)

(5) Reagent density (if injecting liquid reagent)

(e) The Permittee shall maintain records of the boiler load, recirculation pH, liquor feed rate, and number of recirculation pumps in service when the SO2 CEMs is malfunctioning or down for maintenance, repair or adjustments for 24 hours or more, in accordance with Condition D.2.16. The Permittee shall include in its record when readings are not taken and the reason for lack of readings (e.g., the FGD and associated units did not operate).

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

D.2.20 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits. Reports shall be submitted within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.
(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

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

   (1) date of downtime;
   (2) time of commencement;
   (3) duration of each downtime;
   (4) reasons for each downtime; and
   (5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

(c) A quarterly summary of the thirty (30) day rolling weighted average emissions rate in pound per million Btu to document the compliance status with Conditions D.2.1, D.2.4, and 326 IAC 3-5 and a quarterly summary of the daily maximum twenty four (24) hour rolling average emission rates to document the compliance status with Condition D.2.3 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(d) Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.
SECTION D.3  EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(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 PSD Minor Limits [326 IAC 2-2]

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

(a) The nitrogen oxides (NOx) emissions from ABB No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, and the sulfur dioxide (SO2) emissions from ABB No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The amount of distillate oil (No. 2 fuel oil) combusted in ABB No. 3 shall be less than 1,893,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The sulfur content of any fuel used in the turbine (natural gas or oil) shall not exceed 0.3 percent (%) by weight.

Compliance with these limits shall limit the potential to emit from Construction Permit PC (65) 1802, issued on November 6, 1989, of NOx and SO2 to less than forty (40) tons per twelve (12) consecutive month period, each, and shall render the requirements of 326 IAC 2-2 (PSD) not applicable.

D.3.2 Sulfur Dioxide (SO2) [326 IAC 7-1.1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1-2(a)(3) (SO2 Emissions Limitations), the SO2 emissions from ABB Unit No. 3 shall not exceed five-tenths (0.5) pound per MMBtu heat input when combusting distillate oil.

D.3.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for this facility 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.3.4 Parametric Emission Monitoring System (PEMS) for NOx [326 IAC 3-5]

(a) The Permittee shall calibrate, certify, operate and maintain a parametric emissions monitoring system for combustion turbine ABB No.3 stack #3 for NOx and CO2 or O2 in accordance with 326 IAC 3-5-2 through 3-5-7.

(b) The Permittee shall determine compliance with the NOx limit in Condition D.3.1(a) utilizing data from the NOx and CO2 or O2 PEMS.

(c) The Permittee shall submit to IDEM, OAQ, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

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

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

(f) Whenever a NOx PEMS is down for more than twenty-four (24) hours, the Permittee shall follow the best combustion practices.

D.3.5 Sulfur Dioxide Emissions and Sulfur Content

In order to assure compliance with Condition D.3.2, the Permittee shall comply with the following:

(a) Pursuant to 326 IAC 7-2-1(d)(2), compliance shall be determined using a calendar month average sulfur dioxide emission rate in pounds per MMBtu.

(b) Compliance shall be determined using one of the following options:

(i) Pursuant to 326 IAC 7-2-1(h)(3) and (4), the Permittee shall demonstrate compliance by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, in accordance with 326 IAC 3-7 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, accordance with 326 IAC 3-6.

(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.

(ii) Pursuant to 326 IAC 7-2-1(h)(1), compliance may also be determined by conducting a stack test for sulfur dioxide emissions from ABB No. 3 using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.
A determination of noncompliance pursuant to any of the methods specified Condition D.3.5(b)(i) or (ii) above shall not be refuted by evidence of compliance pursuant to the other method.

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

D.3.6 Visible Emissions Notations

(a) When distillate oil is being combusted, visible emission notations of ABB No. 3 stack exhaust 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 a reasonable response. Section C – Response to Excursions and Exceedances contains the Permittee’s obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

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

D.3.7 Record Keeping Requirement

(a) To document the compliance status with NOX Conditions D.3.1(a) and D.3.4, the Permittee shall maintain records of all NOX and CO2 or O2 continuous parametric emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 2-2 and 40 CFR 60.49a. Records shall be complete and sufficient to establish compliance with the NOX limit as required in Conditions D.3.1(a) and D.3.4.

(b) To document the compliance status with Conditions D.3.1(b), D.3.1(c) and D.3.2, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly when distillate oil is combusted and shall be complete and sufficient to establish compliance with the distillate oil usage limit, the fuel sulfur content limit, and the SO2 emission limit established in Conditions D.3.1(b), D.3.1(c) and D.3.2.

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

(2) Actual distillate oil combusted (in kgal) since last compliance determination period and equivalent calculated sulfur dioxide emissions;

(3) To certify compliance when burning natural gas only, the Permittee shall maintain records of fuel used.

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

(i) Fuel supplier certifications;
(ii) The name of the fuel vendor; and
(iii) A statement from the fuel vendor that certifies the sulfur content of the fuel oil.

(5) If oil sampling is used to determine the sulfur content of the oil and to demonstrate compliance, analysis of the oil sample shall be maintained.

(6) If conducting a stack test for sulfur dioxide emissions is used to demonstrate compliance, the stack test results, as a minimum, shall be maintained.

(c) In the event that a breakdown of the NOx parametric emission monitoring systems (PEMS) occurs, the Permittee shall maintain records of all PEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(d) To document the compliance status with Condition D.3.6 - Visible Emission Notation when distillate oil is being combusted, the Permittee shall maintain records of the daily visible emission notations of ABB No. 3 stack exhaust. 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).

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

D.3.8 Reporting Requirements

(a) A quarterly report of NOx emissions and a quarterly summary of the information to document the compliance status with D.3.1(a) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

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

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

(c) A quarterly report of distillate oil usage and a quarterly summary of the information to document compliance with Condition D.3.1(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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).

(d) Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition.
SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOx) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(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 PM10 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD BACT) and Significant Source Mod 129-14021-00001, issued November 16, 2001, the PM10 emissions from ABB No. 4 shall comply with the following:

(a) Gas turbine emissions shall be less than 0.0050 pounds per MMBtu on a higher heating value basis, which is equivalent to five (5) pounds per hour.

(b) Perform good combustion.

D.4.2 NOx PSD BACT [326 IAC 2-2-3]

(a) Pursuant to 326 IAC 2-2-3 (PSD BACT) and Significant Source Mod 129-14021-00001, issued November 16, 2001, ABB No. 4 shall comply with the following:

(1) Use dry low-NOx combustors in conjunction with natural gas.

(2) During normal simple cycle operation (i.e., steady-state operating condition), the NOx emissions from combustion turbine when burning natural gas shall be less than 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 36 pounds per hour.

(b) Pursuant to 326 IAC 2-2-3 (PSD Requirements) and Significant Source Mod 129-14021-00001, the annual NOx emissions from ABB No. 4 burning natural gas shall be less than 132.06 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

D.4.3 CO PSD BACT [326 IAC 2-2-3]

(a) Pursuant to 326 IAC 2-2-3 (PSD BACT) and Significant Source Mod 129-14021-00001, issued November 16, 2001, ABB No. 4 shall comply with the following:

(1) During normal simple cycle operation (i.e., steady-state operating condition), the CO emissions from combustion turbine, when burning natural gas, shall be less than 25 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 60 pounds per hour.

(2) Good combustion practices shall be applied to minimize CO emissions.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements) and Significant Source Mod 129-14021-00001, the annual CO emissions from ABB No. 4 burning natural gas shall be less than
221.52 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

D.4.4 326 IAC 2-2-3 (PSD Requirements) Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2-3 (PSD Requirements) and Significant Source Mod 129-14021-00001, issued November 16, 2001, ABB No. 4 shall meet the following startup and shutdown conditions:

(a) Startup is defined as the period of time between the initiation of combustion firing from a "cold start" operating condition and the attainment of steady-state operating condition.

(b) Shutdown is defined as that period of time between the initial lowering of the turbine output and the complete cessation of fuel combustion in the unit with the intent to shut down to a "cold stop" condition.

(c) ABB No. 4 shall comply with the following:

(A) The maximum number of events (where one event is one startup and one shutdown) shall be less than 240 per twelve (12) consecutive month period rolled on monthly basis as determined at the end of each calendar month. The duration of an event shall not exceed one (1) hour.

(B) The NOx emissions from ABB No. 4 stack shall be less than 36 pounds per event. ABB No. 4 shall emit less than 3.8 tons of NOx during startup and shutdown per twelve (12) consecutive month period, with compliance determined at the end of each month.

(C) The CO emissions from ABB No. 4 stack shall be less than 60 pounds per event. ABB No. 4 shall emit less than 14.27 tons of CO during startup and shutdown per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.4.5 Hazardous Air Pollutants (HAP) Limitations [326 IAC 2-4.1]

Pursuant to Significant Source Mod 129-14021-00001, issued November 16, 2001, and in order to render the requirements of 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP)) not applicable, the Permittee shall comply with the following:

(a) The emission of single HAP formaldehyde from the ABB No. 4 combustion turbine shall be limited to less than 0.00071 lb/MMBtu.

(b) The amount of MMBtu fired in the turbine shall be less than 10,038,960 MMBtu per twelve (12) consecutive month period with compliance determination at the end of each month.

Compliance with these limits shall limit the formaldehyde emissions from ABB No. 4 to less than ten (10) tons per twelve (12) consecutive month period, and shall render the requirements of 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP) not applicable.

D.4.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for this facility. 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.4.7 Continuous Emission Monitoring [326 IAC 2-7-6(1),(6)][326 IAC 2-2][326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission
monitoring systems for ABB No.4 shall be calibrated, maintained, and operated for measuring NOx, CO, and CO2 or O2, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) The continuous emission monitoring system (CEMS) shall measure NOx and CO emissions rates in pounds per hour, uncorrected parts per million, and parts per million on a dry volume basis (ppmvd) corrected to 15% O2. The use of CEMS to measure and record the NOx and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NOx limit, the source shall take an average of the ppmvd corrected to 15% O2 over a twenty four (24) operating hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the ppmvd corrected to 15% O2 over a twenty four (24) hour operating period. The source shall maintain records of the ppmvd corrected to 15% O2 and the pounds per hour.

(c) The Permittee shall determine compliance with Condition D.4.4 utilizing data from the NOx, CO, and CO2 or O2 CEMS, and the fuel flow meter, and Method 19 calculations.

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


(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the “Optional SO2 Emissions Data Protocol for Gas-Fired and Oil Fired Units” protocol.

(2) The Permittee shall apply to IDEM for initial certification to use the “Optional SO2 Emissions Data Protocol for Gas-Fired and Oil Fired Units” protocol, no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

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

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

D.4.8 NOx or CO Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx or CO continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx or CO continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx or CO CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx or CO CEMS, the Permittee shall follow good combustion practices.
D.4.9 Record Keeping Requirement

(a) To document the compliance status with Conditions D.4.1 and D.4.5, the Permittee shall maintain records of the following:

1. Amount of natural gas combusted (in MMCF) during each month;
2. The average heat content on a higher heating value basis.
3. The total MMBtu of fuel combusted in the ABB No. 4 per month.

(b) To document the compliance status with Conditions D.4.2 and D.4.3, the Permittee shall record the emission rates of NOX and CO in ppmvd corrected to 15% oxygen and pounds per hour, and the total monthly NOx and CO emissions, and shall perform the required record keeping pursuant to 326 IAC 3-5-6, 326 IAC 3-5-7, 326 IAC 2-2, and 40 CFR 60.49a.

(c) In the event that a breakdown of the NOx or CO continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(d) To document the compliance status with Condition D.4.4, the Permittee shall maintain records of the following:

1. The type of operation (i.e., startup or shutdown) with supporting operational data;
2. The number of minutes for each event;
3. The CEMS data and fuel flow meter data corresponding to each startup and shutdown period, in accordance with Condition D.4.4(c)(B) and D.4.4(c)(C).

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

D.4.10 Reporting Requirements

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(f).

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).

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

1. date of downtime;
2. time of commencement;
3. duration of each downtime;
4. reasons for each downtime; and
5. nature of system repairs and adjustments.
The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

(c) A quarterly summary of the CEMS data to document compliance with Conditions D.4.2 and D.4.3, shall be submitted not later than thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(35).

(d) A quarterly report of the total number of startup and shutdown events and a quarterly summary of the information to document the compliance status with Condition D.4.4 shall be submitted not later than thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition.
SECTION D.5  EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit No. 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

1. One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.
2. One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.
3. An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.
4. Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers.

Insignificant Activities:

(d) 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.5.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) the allowable particulate emission from the coal storage and handling system shall not exceed 71.2 pounds per hour when operating at a process weight rate of 600 tons per hour (1,200,000 pounds per hour).

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

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

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

When the process weight rate exceeds two hundred (200) tons per hour, the maximum allowable emission may exceed 71.2 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.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emissions from the coal bunker and scale exhausts, and associated dust collector vents shall not exceed the amounts determined by the following:
(1) Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

where \( E \) = rate of emission in pounds per hour

and \( P \) = process weight rate in tons per hour

(2) 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

(3) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emissions may exceed the pounds per hour limitation calculated using the above equation, provided the concentration of particulate in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1000) pounds of gases.

D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for these facilities and control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.5.3 Particulate Control

In order to comply with Condition D.5.1, the water mist curtain for particulate control shall be in operation and control emissions from the coal storage and handling system (railcar and truck unloading) at all times the coal storage and handling system (railcar and truck unloading) is in operation, unless there is adequate atmospheric precipitation to control emissions or unless the coal is so damp as to control emissions.

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

D.5.4 Visible Emission Notations

(a) Visible emission notations of any coal transfer exhaust point, coal bunker and scale exhausts, and associated dust collector vents shall be performed once per week during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the railcar and truck unloading shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

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

(d) 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.

(e) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
(f) If abnormal emissions are observed crossing the property line or boundaries of the property, right of way, or easement on which the source is located, the Permittee shall take a reasonable response. Section C – Response to Excursions and Exceedances contains the Permittee’s obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

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

D.5.5 Record Keeping Requirement

(a) To document the compliance status with Condition D.5.4(a) - Visible Emission Notations, the Permittee shall maintain records of weekly visible emission notations of the coal transfer point exhaust, coal bunker and scale exhausts, and associated dust collector vents. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that week).

(b) To document the compliance status with Condition D.5.4(b) - Visible Emission Notations, the Permittee shall maintain records of daily visible emission notations of the railcar and truck unloading exhaust. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

(c) The visible emission notation records for the railcar and truck unloading station performed under Condition D.5.4 also shall identify:

(1) Whether there is sufficient atmospheric precipitation to inhibit the formation of visible dust during coal unloading, and

(2) Whether the coal is sufficiently wet to inhibit the formation of visible dust during coal unloading.

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

Emissions Unit Description:

(f) A lime storage and handling system with maximum loading of 42000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

(1) One (1) railcar and truck unloading station, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.

(2) Two (2) storage silos, each with a maximum capacity of 1300 tons, each with a fabric filter to recover the pneumatically conveyed material.

(3) One (1) storage silo, with a storage capacity of 2600 tons, each with a fabric filter to recover the pneumatically conveyed material.

(4) Three (3) usage bins, each with a storage capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(g) A soda ash storage and handling system with maximum loading of 6000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

(1) One (1) railcar and truck unloading station, with particulate matter emissions controlled by enclosure, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.

(2) Two (2) storage silos, each with a maximum capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

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

Pursuant to 326 IAC 6-3-2(e) (Particulate Emission Limitations for Manufacturing Processes) the allowable particulate emission from the lime storage and handling system and soda ash storage and handling system shall not exceed the amounts determined by the following:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

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

<table>
<thead>
<tr>
<th>Unit Description</th>
<th>Process Weight Rate (ton/hr)</th>
<th>PM Limit (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lime Storage &amp; Handling System</td>
<td>21</td>
<td>31.5</td>
</tr>
<tr>
<td>Soda Ash Storage &amp; Handling System</td>
<td>3</td>
<td>8.56</td>
</tr>
</tbody>
</table>
D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for these facilities and any control devices. 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 2-7-5(1)][326 IAC 2-7-6(1)]

D.6.3 Visible Emissions Notations

(a) Visible emission notations of the lime storage and handling system transfer point exhausts and the soda ash storage and handling system transfer point 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 that specific process.

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

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

D.6.4 Record Keeping Requirement

(a) To document the compliance status with Condition D.6.3 - Visible Emission Notations, the Permittee shall maintain records of daily visible emission notations of the lime storage and handling system transfer point exhausts and the soda ash storage and handling system transfer point 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 process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.
SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) The wet fly and bottom ash handling system was installed and expanded with start-up dates of 1979 (installed with Boiler Unit No. 1) and 1985 (installed with Boiler Unit No. 2). The dry fly ash (DFA) system was subsequently added to accommodate the option for product recovery of DFA material through a separate storage, handling, and barging operation to an off-site location. The DFA handling system interfaces with the existing wet ash system at the Hydroveyor. (Hydroveyor No. 1 for A. B. Brown No. 1 and Hydroveyor No. 2 for A. B. Brown No. 2). Each existing Hydroveyor is a water-exhauster powered-vacuum system that conveys ash in a dry state up to the exhauster where it then converts to slurry form and then flows to an ash separator where the conveying air is vented off and the slurry flows by gravity to the existing ash pond. The existing handling system was modified to incorporate the all-dry filter/separator design (Filter/Separator No. 1 for A. B. Brown No. 1 and Filter/Separator No. 2 for A. B. Brown No. 2). Each Hydroveyor remains in-service and each filter/separator, with bypasses, intercept the fly ash for transport to the storage silo. Each existing Hydroveyor continues to discharge water to the existing ash pond and the existing fly ash system continues to route fly ash slurry flows to the ash pond for maintenance or product quality episodes. The filter/separators discharge to the Intermediate Silo (storage capacity of 2500 tons). The Intermediate Silo is equipped with a bin vent filter and truck unloading station. The truck unloading station receives ash from other Vectren operations for transfer to the Barge Loader. The truck unloading station is equipped with two truck bays to receive ash product. The transport and handling system that extends from the Intermediate Silo and through to the Barge Loader is a common (single) system with a design capacity of 700 ton/hr. The Intermediate Silo discharge is fitted with a feeder to load the dry conveyor (belt) for transport to the Barge Loading Transfer Tower. The Barge Loading Transfer Tower conveys DFA, via air-slide, to the barge. The DFA product enters the barge through a telescopic loading nozzle fitted with a dust control ring to control fugitive dust. The Barge Loader conveyor is equipped with a fabric filter dust collector which vents to the atmosphere.

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, with modification in 1984 and 1985 for Unit No. 2 boiler, with wet sludge conveyed to haul trucks.

(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 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 emissions from the Barge Loader system exhausts shall not exceed the amounts determined by the following:

(a) Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

where \( E \) = rate of emission in pounds per hour and

\( P \) = process weight rate in tons per hour

(b) 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

(c) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emissions may exceed the pounds per hour limitation calculated using the above equation, provided the concentration of particulate in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1000) pounds of gases.

D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]
A Preventive Maintenance Plan (PMP) is required for these facilities and any control devices. 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 2-7-5(1)][326 IAC 2-7-6(1)]

D.7.3 Visible Emissions Notations
(a) Visible emission notations of the Barge Loader system exhausts shall be performed once per week 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 crossing the property line or boundaries of the property, right of way, or easement on which the source is located, the Permittee shall take a reasonable response. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

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

D.7.4 Record Keeping Requirement
(a) To document the compliance status with Condition D.7.3, the Permittee shall maintain records of weekly visible emission notations of the Barge Loader system exhausts. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that week).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.
SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

Insignificant Activities:

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

(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 Compound (VOC) [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), the Permittee shall:

(a) Ensure the following control equipment and operating requirements are met:

(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 subdivisions (3), (4), (6), and (7).

(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) 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 clauses (A) through (D) 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), the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]
A Preventive Maintenance Plan (PMP) is required for these facilities. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]
D.8.4 Record Keeping Requirements
(a) To document the compliance status with Condition D.8.2, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(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 contains the Permittee's obligations with regard to the records required by this condition.
Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO₂), with low-nitrogen oxides (NOₓ) combustion (low-excess air and low NOₓ burners) and selective catalytic reduction (SCR) system for control of NOₓ, with sorbent injection system for control of sulfur trioxide (SO₃) and resulting sulfuric acid (H₂SO₄) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOₓ, SO₂, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(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.1.1 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 emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart D.

(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 Fossil - Fuel Steam Generators for Which Construction is Commenced After August 17, 1971 NSPS [326 IAC 12] [40 CFR Part 60, Subpart D]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart D (included as Attachment B to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40(a)(1)
(2) 40 CFR 60.41
(3) 40 CFR 60.42(c)
(4) 40 CFR 60.43
(5) 40 CFR 60.44
(6) 40 CFR 60.45 and
(7) 40 CFR 60.46
SECTION E.2  NSPS

**Emissions Unit Description:**

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low-NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]  
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

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

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**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 emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Da.

(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 Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]**

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Da (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

1. 40 CFR 60.40Da (a)(1) and (a)(2)
2. 40 CFR 60.41Da
3. 40 CFR 60.42Da (a) and (b)(1)
4. 40 CFR 60.43Da (a)(1) through (a)(4), and (g)
5. 40 CFR 60.44Da (a)(1)
6. 40 CFR 60.48Da (a), (b), (d), (e), (f), (h), (q), & (s)
7. 40 CFR 60.49Da (a)(1), (b)(1), (b)(4), (c), (d), (e), (f)(1), (g), (h), (i), (j), (s), (t), (v), & (w)
8. 40 CFR 60.50Da (a), (b)(1), (b)(3), (c), (d), & (e)
9. 40 CFR 60.51Da (a), (b), (c), (f), (h), (i), (j), & (k)
10. 40 CFR 60.52Da
SECTION E.3  NSPS

Emissions Unit Description:

(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOX) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(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.3.1 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 emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GG.

(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.3.2 Stationary Gas Turbines NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart GG (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.330(a) and (b)
(2) 40 CFR 60.331
(3) 40 CFR 60.332(a)(1), (a)(3), (a)(4), (b), (f), and (k)
(4) 40 CFR 60.333
(5) 40 CFR 60.334(a), (b), (g), (h), (i)(2), (i)(3), (j)(1)(i), (j)(1)(i)(ii), (j)(2)(i), (j)(2)(ii), (j)(3), (j)(4), and (j)(5)
(6) 40 CFR 60.335(a), (b), and (c)
SECTION E.4 NESHAP

Emissions Unit Description:

Insignificant Activities:

(b) Two (2) distillate oil-fired emergency generators rated 398 bhp each, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, these are affected facilities.]

(c) One (1) distillate oil-fired fire pump rated 200 bhp, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, this is an affected facility]

(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)]


(a) Pursuant to 40 CFR 63.1 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, for the emission unit(s) listed above, except as otherwise specified 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.4.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 20-82, for the emission unit(s) listed above:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(a) and (b)
(3) 40 CFR 63.6590(a)(1)(ii) and (a)(1)(iv)
(4) 40 CFR 63.6595 (a)(4) and (c)
(5) 40 CFR 63.6602
(6) 40 CFR 63.6604(b)
(7) 40 CFR 63.6605
(8) 40 CFR 63.6612 (a) and (b) (Testing)
(9) 40 CFR 63.6620(a)
(10) 40 CFR 63.6625(e)(2), (f), (h), and (i)
(11) 40 CFR 63.6630(a), (b), and (c)
(12) 40 CFR 63.6635
(13) 40 CFR 63.6640 (a), (f)(1), (f)(2)(i), (f)(3)
E.4.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for these facilities. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.
SECTION E.6  NESHAP

**Emissions Unit Description:**

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[b]Under 40 CFR 60, Subpart D, this is an affected facility[b]
[b]Under 40 CFR 63, Subpart UUUUU, this is an affected facility[b]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low -NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[b]Under 40 CFR 60, Subpart Da, this is an affected facility[b]
[b]Under 40 CFR 63, Subpart UUUUU, this is an affected facility[b]

(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)]**


(a) Pursuant to 40 CFR 63.1 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, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU.

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
E.6.2 Coal and Oil Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUUUU (included as Attachment F to the operating permit), which are incorporated by reference as 326 IAC 20-89, for the emission unit(s) listed above:

(1) 40 CFR 63.9980
(2) 40 CFR 63.9981
(3) 40 CFR 63.9982 (a)(1)
(4) 40 CFR 63.9984 (b)
(5) 40 CFR 63.9990 (a)(1)
(6) 40 CFR 63.9991
(7) 40 CFR 63.10000 (a), (b),(c)(1), (d),& (e)
(8) 40 CFR 63.10005(a)(2), (d), (e), (j), and (k)
(9) 40 CFR 63.10006(a), (c), (f), (g), and (i)
(10) 40 CFR 63.10007(a)(1), (b), (d), (e)(1), (e)(3), (f), and (g)
(11) 40 CFR 63.10009(a), (b), (c), (d), (e), (f)(1), (h), and (j)(1)
(12) 40 CFR 63.10010(a)(1), (e), (f), (g), (j), and (l)
(13) 40 CFR 63.10011(a), (c), (e), (f), (g)
(14) 40 CFR 63.10020(a), (b), (c), (d), (e)(1), and (e)(2)
(15) 40 CFR 63.10021(a), (b), (e), (f), (g), (h), and (l)
(16) 40 CFR 63.10022(a)(1), (a)(4), and (b)
(17) 40 CFR 63.10030(a), (b), (d), and (e)
(18) 40 CFR 63.10031(a), (b), (c), (d), (e), (f), and (g)
(19) 40 CFR 63.10032(a), (b), (f), and (h)
(20) 40 CFR 63.10033
(21) 40 CFR 63.10040
(22) 40 CFR 63.10041
(23) 40 CFR 63.10042
(24) Item 1 of Table 1 to Subpart UUUUU of Part 63
(25) Item 1 of Table 2 to Subpart UUUUU of Part 63
(26) Items 1, 3, and 4 of Table 3 to Subpart UUUUU of Part 63
(27) Items 1, 3, 4, and 5 of Table 5 to Subpart UUUUU of Part 63
(28) Items 1, 4, 5, 6, and 7 of Table 7 to Subpart UUUUU of Part 63
(29) Item 1 of Table 8 to Subpart UUUUU of Part 63
(30) Table 9 to Subpart UUUUU of Part 63
(31) Appendix A to Subpart UUUUU of Part 63
(32) Appendix B to Subpart UUUUU of Part 63
SECTION E.7 Acid Rain Program

ORIS Code:  6137

Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low -NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOx) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

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

E.7.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]

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

E.7.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

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

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

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

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

ORIS Code: 6137

Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOx) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

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

F.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated
representative, and may have an alternate designated representative, in accordance with the following:

(a) 40 CFR 97.413 through 97.418;
(b) 40 CFR 97.513 through 97.518; and
(c) 40 CFR 97.613 through 97.618.

F.2  Emissions monitoring, reporting, and recordkeeping requirements

(a) The owners and operators, and the designated representative, of each TR NOx Annual source, TR NOx Ozone Season source, and TR SO2 Group 1 source, and each TR NOx Annual unit at the source, TR NOx Ozone Season unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.530, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.531, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.532, and 97.632 (monitoring system out-of-control periods), 97.433, 97.533, and 97.633 (notifications concerning monitoring), 97.434, 97.534, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.535, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(b) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NOx Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NOx Annual emissions limitation and assurance provisions under Condition F.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NOx Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NOx Ozone Season emissions limitation and assurance provisions under Condition F.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(d) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO2 Group 1 emissions limitation and assurance provisions under Condition F.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.
F.3 NOX Annual Emissions Requirements

(a) TR NOX Annual emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOX Annual source and each TR NOX Annual unit at the source shall hold, in the source's compliance account, TR NOX Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NOX emissions for such control period from all TR NOX Annual units at the source.

(2) If total NOX emissions during a control period in a given year from the TR NOX Annual units at a TR NOX Annual source are in excess of the TR NOX Annual emissions limitation set forth in Condition F.3(a)(1) above, then:

(A) The owners and operators of the source and each TR NOX Annual unit at the source shall hold the TR NOX Annual allowances required for deduction under 40 CFR 97.424(d); and

(B) The owners and operators of the source and each TR NOX Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(b) TR NOX Annual assurance provisions.

(1) If total NOX emissions during a control period in a given year from all TR NOX Annual units at TR NOX Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such NOX emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOX Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying—(A) The quotient of the amount by which the common designated representative’s share of such NOX emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such NOX emissions exceeds the respective common designated representative’s assurance level; and (B) The amount by which total NOX emissions from all TR NOX Annual units at TR NOX Annual sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the TR NOX Annual allowances required under Condition F.3(b)(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(3) Total NOX emissions from all TR NOX Annual units at TR NOX Annual sources in the State during a control period in a given year exceed the state assurance level.
if such total NOx emissions exceed the sum, for such control period, of the state
NOx Annual trading budget under 40 CFR 97.410(a) and the state’s variability
limit under 40 CFR 97.410(b).

(4) It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air
Act if total NOx emissions from all TR NOx Annual units at TR NOx Annual
sources in the State during a control period exceed the state assurance level or if
a common designated representative’s share of total NOx emissions from the TR
NOx Annual units at TR NOx Annual sources in the state during a control period
exceeds the common designated representative’s assurance level.

(5) To the extent the owners and operators fail to hold TR NOx Annual allowances
for a control period in a given year in accordance with Conditions F.3(b)(1)
through (3) above,
(A) The owners and operators shall pay any fine, penalty, or assessment or
comply with any other remedy imposed under the Clean Air Act; and
(B) Each TR NOx Annual allowance that the owners and operators fail to
hold for such control period in accordance with Conditions F.3(b)(1)
through (3) above and each day of such control period shall constitute a
separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air
Act.

(c) Compliance periods.

(1) A TR NOx Annual unit shall be subject to the requirements under Condition
F.3(a) above for the control period starting on the later of January 1, 2015, or the
deadline for meeting the unit’s monitor certification requirements under 40 CFR
97.430(b) and for each control period thereafter.

(2) A TR NOx Annual unit shall be subject to the requirements under Condition
F.3(b) above for the control period starting on the later of January 1, 2017 or the
deadline for meeting the unit’s monitor certification requirements under 40 CFR
97.430(b) and for each control period thereafter.

(d) Vintage of allowances held for compliance.

(1) A TR NOx Annual allowance held for compliance with the requirements under
Condition F.3(a)(1) above for a control period in a given year must be a TR NOx
Annual allowance that was allocated for such control period or a control period in
a prior year.

(2) A TR NOx Annual allowance held for compliance with the requirements under
Condition F.3(a)(2)(1) and (b)(1) through (3) above for a control period in a given
year must be a TR NOx Annual allowance that was allocated for a control period
in a prior year or the control period in the given year or in the immediately
following year.

(e) Allowance Management System requirements. Each TR NOx Annual allowance shall be
held in, deducted from, or transferred into, out of, or between Allowance Management
System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.

(f) Limited authorization. A TR NOx Annual allowance is a limited authorization to emit one
ton of NOx during the control period in one year. Such authorization is limited in its use
and duration as follows:
(1) Such authorization shall only be used in accordance with the TR NOX Annual Trading Program; and

(2) Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(g) Property right. A TR NOX Annual allowance does not constitute a property right.

### F.4 NOx Ozone Season Requirements

#### (a) TR NOx Ozone Season emissions limitation.

1. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall hold, in the source's compliance account, TR NOx Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Ozone Season units at the source.

2. If total NOx emissions during a control period in a given year from the TR NOx Ozone Season units at a TR NOx Ozone Season source are in excess of the TR NOx Ozone Season emissions limitation set forth in Condition F.4(a)(1) above, then:

   - (A) The owners and operators of the source and each TR NOx Ozone Season unit at the source shall hold the TR NOx Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

   - (B) The owners and operators of the source and each TR NOx Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart BBBBB and the Clean Air Act.

#### (b) TR NOx Ozone Season assurance provisions.

1. If total NOx emissions during a control period in a given year from all TR NOx Ozone Season units at TR NOx Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such NOx emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOx Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying:

   - (A) The quotient of the amount by which the common designated
representative’s share of such NOx emissions exceeds the common
designated representative’s assurance level divided by the sum of the
amounts, determined for all common designated representatives for such
sources and units in the state for such control period, by which each
common designated representative’s share of such NOx emissions
exceeds the respective common designated representative’s assurance
level; and

(B) The amount by which total NOx emissions from all TR NOx Ozone
Season units at TR NOx Ozone Season sources in the state for such
control period exceed the state assurance level.

(2) The owners and operators shall hold the TR NOx Ozone Season allowances
required under Condition F.4(b)(1) above, as of midnight of November 1 (if it is a
business day), or midnight of the first business day thereafter (if November 1 is
not a business day), immediately after such control period.

(3) Total NOx emissions from all TR NOx Ozone Season units at TR NOx Ozone
Season sources in the state during a control period in a given year exceed the
state assurance level if such total NOx emissions exceed the sum, for such
control period, of the State NOx Ozone Season trading budget under 40 CFR
97.510(a) and the state’s variability limit under 40 CFR 97.510(b).

(4) It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air
Act if total NOx emissions from all TR NOx Ozone Season units at TR NOx
Ozone Season sources in the state during a control period exceed the state
assurance level or if a common designated representative’s share of total NOx
emissions from the TR NOx Ozone Season units at TR NOx Ozone Season
sources in the state during a control period exceeds the common designated
representative’s assurance level.

(5) To the extent the owners and operators fail to hold TR NOx Ozone Season
allowances for a control period in a given year in accordance with Conditions
F.4(b)(1) through (3) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or
comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NOX Ozone Season allowance that the owners and operators
fail to hold for such control period in accordance with Conditions
F.4(b)(1) through (3) above and each day of such control period shall
constitute a separate violation of 40 CFR Part 97, Subpart BBBBB and
the Clean Air Act.

(c) Compliance Periods.

(1) A TR NOx Ozone Season unit shall be subject to the requirements under
Condition F.4(a) above for the control period starting on the later of May 1, 2015
or the deadline for meeting the unit's monitor certificate requirements under 40
CFR 97.530(b) and for each control period thereafter.

(2) A TR NOx Ozone Season unit shall be subject to the requirements under
Condition F.4(b) above for the control period starting on the later of May 1, 2017
or the deadline for meeting the unit's monitor certification requirements under 40
CFR 97.530(b) and for each control period thereafter.
(d) Vintage of allowances held for compliance.

(1) A TR NOx Ozone Season allowance held for compliance with the requirements under Condition F.4(a)(1) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.

(2) A TR NOx Ozone Season allowance held for compliance with the requirements under Conditions F.4(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(e) Allowances Management System Requirements.

(1) Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBBB.

(f) Limited Authorization.

(1) A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A) Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and

(B) Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(g) Property Right.

(1) A TR NOx Ozone Season allowance does not constitute a property right.

F.5 SO\textsubscript{2} Emissions Requirements

(a) TR SO\textsubscript{2} Group 1 emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO\textsubscript{2} Group 1 source and each TR SO\textsubscript{2} Group 1 unit at the source shall hold, in the source's compliance account, TR SO\textsubscript{2} Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO\textsubscript{2} emissions for such control period from all TR SO\textsubscript{2} Group 1 units at the source.

(2) If total SO\textsubscript{2} emissions during a control period in a given year from the TR SO\textsubscript{2} Group 1 units at a TR SO\textsubscript{2} Group 1 source are in excess of the TR SO\textsubscript{2} Group 1 emissions limitation set forth in Condition F.5(a)(1) above, then:

(A) The owners and operators of the source and each TR SO\textsubscript{2} Group 1 unit at the source shall hold the TR SO\textsubscript{2} Group 1 allowances required for deduction under 40 CFR 97.624(d); and
(B) The owners and operators of the source and each TR SO\textsubscript{2} Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCC and the Clean Air Act.

(b) TR SO\textsubscript{2} Group 1 assurance provisions

(1) If total SO\textsubscript{2} emissions during a control period in a given year from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such SO\textsubscript{2} emissions during such control period exceeds the common designated representative’s assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO\textsubscript{2} Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(2) The quotient of the amount by which the common designated representative’s share of such SO\textsubscript{2} emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative’s share of such SO\textsubscript{2} emissions exceeds the respective common designated representative’s assurance level; and

(3) The amount by which total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in the state for such control period exceed the state assurance level.

(4) The owners and operators shall hold the TR SO\textsubscript{2} Group 1 allowances required under Condition F.5(b)(1) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(5) Total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO\textsubscript{2} emissions exceed the sum, for such control period, of the state SO\textsubscript{2} Group 1 trading budget under 40 CFR 97.610(a) and the state’s variability limit under 40 CFR 97.610(b).

(6) It shall not be a violation of 40 CFR part 97, subpart CCCC or of the Clean Air Act if total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative’s share of total SO\textsubscript{2} emissions from the TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in the state during a control period exceeds the common designated representative’s assurance level.

(7) To the extent the owners and operators fail to hold TR SO\textsubscript{2} Group 1 allowances for a control period in a given year in accordance with Conditions F.5(b)(1) through (3) above,
(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO₂ Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Conditions F.5(b)(1) through (3) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(c) Compliance periods.

(1) A TR SO₂ Group 1 unit shall be subject to the requirements under Condition F.5(a) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(2) A TR SO₂ Group 1 unit shall be subject to the requirements under Condition F.5(b) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(d) Vintage of allowances held for compliance.

(1) A TR SO₂ Group 1 allowance held for compliance with the requirements under Condition F.5(a)(1) above for a control period in a given year must be a TR SO₂ Group 1 allowance that was allocated for such control period or a control period in a prior year.

(2) A TR SO₂ Group 1 allowance held for compliance with the requirements under Condition F.5(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a TR SO₂ Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(e) Allowance Management System requirements. Each TR SO₂ Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.

(f) Limited authorization. A TR SO₂ Group 1 allowance is a limited authorization to emit one ton of SO₂ during the control period in one year. Such authorization is limited in its use and duration as follows:

(1) Such authorization shall only be used in accordance with the TR SO₂ Group 1 Trading Program; and

(2) Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(g) Property right. A TR SO₂ Group 1 allowance does not constitute a property right.
F.6 Title V Permit Revision Requirements

(a) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NOx Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAAA, TR NOx Ozone Season allowances in accordance with 40 CFR Part 97, Subpart BBBBBB, and TR SO2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.

(b) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

F.7 Additional recordkeeping and reporting requirements

(a) Unless otherwise provided, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit, TR NOx Ozone Season source and each TR NOx Ozone Season unit, and TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(1) The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NOx Annual unit, TR NOx Ozone Season unit, and TR SO2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAAA, 40 CFR Part 97, Subpart BBBBBB, and 40 CFR Part 97, Subpart CCCCC.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOx Annual Trading Program, TR NOx Ozone Season Trading Program, and TR SO2 Group 1 Trading Program.

(b) The designated representative of a TR NOx Annual source and each TR NOx Annual unit, a TR NOx Ozone Season source and each TR NOx Ozone Season unit, and a TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall make all submissions required under the TR NOx Annual Trading Program, TR NOx Ozone Season Trading Program, and TR SO2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.
F.8  Liability

(a) Any provision of the TR NO\textsubscript{X} Annual Trading Program that applies to a TR NO\textsubscript{X} Annual source or the designated representative of a TR NO\textsubscript{X} Annual source shall also apply to the owners and operators of such source and of the TR NO\textsubscript{X} Annual units at the source.

(b) Any provision of the TR NO\textsubscript{X} Annual Trading Program that applies to a TR NO\textsubscript{X} Annual unit or the designated representative of a TR NO\textsubscript{X} Annual unit shall also apply to the owners and operators of such unit.

(c) Any provision of the TR NO\textsubscript{X} Ozone Season Trading Program that applies to a TR NO\textsubscript{X} Ozone Season source or the designated representative of a TR NO\textsubscript{X} Ozone Season source shall also apply to the owners and operators of such source and of the TR NO\textsubscript{X} Ozone Season units at the source.

(d) Any provision of the TR NO\textsubscript{X} Ozone Season Trading Program that applies to a TR NO\textsubscript{X} Ozone Season unit or the designated representative of a TR NO\textsubscript{X} Ozone Season unit shall also apply to the owners and operators of such unit.

(e) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 source or the designated representative of a TR SO\textsubscript{2} Group 1 source shall also apply to the owners and operators of such source and of the TR SO\textsubscript{2} Group 1 units at the source.

(f) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 unit or the designated representative of a TR SO\textsubscript{2} Group 1 unit shall also apply to the owners and operators of such unit.

F.9  Effect on other authorities

No provision of the TR NO\textsubscript{X} Annual Trading Program or exemption under 40 CFR 97.405, TR NO\textsubscript{X} Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO\textsubscript{2} Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO\textsubscript{X} Annual source or TR NO\textsubscript{X} Annual unit, TR NO\textsubscript{X} Ozone Season source or TR NO\textsubscript{X} Ozone Season unit, and TR SO\textsubscript{2} Group 1 source or TR SO\textsubscript{2} Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

F.10  Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NO\textsubscript{X} Annual Trading Program and TR NO\textsubscript{X} Ozone Season Trading Program and TR SO\textsubscript{2} Group 1 Trading Program.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO₂ monitoring) and 40 CFR part 75, subpart H (for NOₓ monitoring)</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
<th>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</th>
<th>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix E</th>
<th>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</th>
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#### ORIS ID: 6137

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1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA’s website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative monitoring system is available on the EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit’s monitoring system description.
Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T 129-40544-00010

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:
PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T 129-40544-00010

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: |

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

<table>
<thead>
<tr>
<th>Date/Time Emergency started:</th>
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<tbody>
<tr>
<td>Date/Time Emergency was corrected:</td>
</tr>
<tr>
<td>Was the facility being properly operated at the time of the emergency?</td>
</tr>
<tr>
<td>Type of Pollutants Emitted: TSP, PM-10, SO₂, VOC, NOₓ, CO, Pb, other:</td>
</tr>
<tr>
<td>Estimated amount of pollutant(s) emitted during emergency:</td>
</tr>
<tr>
<td>Describe the steps taken to mitigate the problem:</td>
</tr>
<tr>
<td>Describe the corrective actions/response steps taken:</td>
</tr>
<tr>
<td>Describe the measures taken to minimize emissions:</td>
</tr>
</tbody>
</table>

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: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station  
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620  
Part 70 Permit No.: T 129-40544-00010  
Facility: Turbine ABB No. 3  
Parameter: NOx  
Limit: Less than 40 tons per twelve (12) consecutive month period

<table>
<thead>
<tr>
<th>QUARTER :</th>
<th>YEAR:</th>
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<tr>
<th>Month</th>
<th>Column 1</th>
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</thead>
<tbody>
<tr>
<td>This Month (Tons)</td>
<td>Previous 11 Months (Tons)</td>
<td>12 Month Total (Tons)</td>
<td></td>
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</tbody>
</table>

- [ ] No deviation occurred in this quarter.
- [ ] Deviation/s occurred in this quarter. Deviation has been reported on:

Submitted by:  
Title / Position:  
Signature:  
Date:  
Phone: 
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT  
OFFICE OF AIR QUALITY  
COMPLIANCE AND ENFORCEMENT BRANCH  

Part 70 Quarterly Report  

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station  
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620  
Part 70 Permit No.: T 129-40544-00010  
Facility: Turbine ABB No. 3  
Parameter: Distillate oil (No. 2 fuel oil) usage  
Limit: Less than 1,893,000 gallons per twelve (12) consecutive month period  

<table>
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<tr>
<th>QUARTER:</th>
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<tr>
<th>Month</th>
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<tr>
<td>This Month (Gallons)</td>
<td>Previous 11 Months (Gallons)</td>
<td>12 Month Total (Gallons)</td>
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- □ No deviation occurred in this quarter.  
- □ Deviation/s occurred in this quarter.  
  Deviation has been reported on:  

Submitted by:  
Title / Position:  
Signature:  
Date:  
Phone:  

[Signature]

[Date]  
[Phone]
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T 129-40544-00010
Facility: Turbine ABB No. 4
Parameter: Startup/Shutdown Events
Limit: less than 240 events (where one event is one startup and one shutdown) per twelve (12) month period (each event shall not exceed 1 hour)

<table>
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<tr>
<th>QUARTER</th>
<th>YEAR</th>
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<tr>
<td>Column 1</td>
<td>Column 2</td>
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<tr>
<td>This Month (Events)</td>
<td>Previous 11 Months (Events)</td>
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</table>

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.

Deviation has been reported on:

Submitted by: ____________________________
Title / Position: ____________________________
Signature: ____________________________
Date: ____________________________
Phone: ____________________________
**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**  
**OFFICE OF AIR QUALITY**  
**COMPLIANCE AND ENFORCEMENT BRANCH**  
**PART 70 OPERATING PERMIT**  
**QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT**

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station  
Source Address: 8511 Welborn Road, Mount Vernon, Indiana 47620  
Part 70 Permit No.: T 129-40544-00010

| Months: __________ to __________ | Year: __________ |

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 #)

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<th>Date of Deviation:</th>
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<th>Probable Cause of Deviation:</th>
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<th>Response Steps Taken:</th>
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<th>Response Steps Taken:</th>
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<td>Permit Requirement (specify permit condition #)</td>
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<td>Date of Deviation:</td>
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<tr>
<td>Probable Cause of Deviation:</td>
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<td>Response Steps Taken:</td>
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<td>Probable Cause of Deviation:</td>
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<td>Response Steps Taken:</td>
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<td>Probable Cause of Deviation:</td>
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<td>Response Steps Taken:</td>
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Form Completed by: _____________________________
Title / Position: ______________________________
Date: ______________________________
Phone: ______________________________
Fugitive Dust Control Plan

Southern Indiana Gas and Electric Company (SIGECO) – A.B. Brown Generating Station
8511 Welborn Road, Mount Vernon, IN 47620
Source ID: 129-00010

1: Fugitive particulate matter (dust) emissions from paved roads, unpaved roads, and parking lots shall be controlled by one or more of the following measures:

A: Paved Roads and parking lots:
   a: Treating with water on an as needed basis.

B: Unpaved roads:
   a: Treating with water on an as needed basis.

2: Fugitive particulate matter (dust) emissions from aggregate (coal, ash) stockpiles shall be controlled by the following measures:

A: Treating the coal stockpile with water on an as needed basis.
B: Keeping ash generally submerged in the pond. In areas were ash is exposed, dusting may be controlled by operating a water spray or fogging system; using wind barriers, compaction, or vegetative covers; or through the use of a commercial dust control product.

3: Fugitive particulate matter (dust) emissions from outdoor conveying of aggregates (coal, ash) shall be controlled by the following measure:

A: Enclosed conveyors.

4: Fugitive particulate matter (dust, ash) emissions resulting from the transferring of aggregates (coal) shall be controlled by the following measures:

A: Enclosed transfer points.

5: Fugitive particulate matter (dust) emissions resulting from transportation of aggregate (coal) by truck, front end loader, etc…shall be controlled by one or more of the following measures:

A: Tarping the aggregate hauling vehicles.
B: Maintain vehicle bodies in a condition to prevent leakage.
C: Limit speed within the coal yard in order to prevent fugitive dust emissions.

6: Fugitive particulate matter (dust) emissions resulting from the loading and unloading of aggregates (coal, ash) shall be controlled by one or more of the following measures:

A: Enclosure of the railcar and truck coal unloading station.
B: Enclosure of the truck ash unloading station.
C: Use of the dust control ring fitted to the barge ash loadout station to control fugitive dust.
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Application and designation of affected facilities.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.


§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see § 60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.
Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.


§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with § 60.42Da(a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.42Da(a) of subpart Da of this part.

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO2 or PM is exempt from the PM standards specified in paragraph (a) of this section.
§ 60.43 Standard for sulfur dioxide (SO\textsubscript{2}).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO\textsubscript{2} in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

\[
PSO_2 = \frac{y}{100} \times 340 + \frac{z}{100} \times 520
\]

Where:

\(PSO_2\) = Prorated standard for SO\textsubscript{2} when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

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

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

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

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

§ 60.44 Standard for nitrogen oxides (NO\textsubscript{X}).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO\textsubscript{X}, expressed as NO\textsubscript{2} in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.
(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

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

Where:

- $w = \text{Percentage of total heat input derived from lignite}$;
- $x = \text{Percentage of total heat input derived from gaseous fossil fuel}$;
- $y = \text{Percentage of total heat input derived from liquid fossil fuel}$; and
- $z = \text{Percentage of total heat input derived from solid fossil fuel (except lignite)}$.

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NOx does not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO2 emissions, NOx emissions, and either oxygen ($O_2$) or carbon dioxide ($CO_2$) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:
(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO₂ or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO₂ emissions are not required if the owner or operator monitors SO₂ emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO₂ emissions is not required if the owner or operator monitors SO₂ emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NOₓ may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NOₓ are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NOₓ emissions is not required. If the initial performance test results show that NOₓ emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NOₓ within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO₂ or NOₓ, a CEMS for measuring either O₂ or CO₂ is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first
discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(7) An owner or operator of an affected facility subject to an opacity standard under § 60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section, shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (b)(7) of this section within 45 calendar days according to the requirements in § 60.46(b)(3).
(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUU of part 63.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO2 and NOX continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in § 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NOx the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, SO2 and NOx span values shall be determined as follows:

<table>
<thead>
<tr>
<th>Fossil fuel</th>
<th>Span value for SO2</th>
<th>Span value for NOx</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>(%)</td>
<td>500.</td>
</tr>
<tr>
<td>Liquid</td>
<td>1,000</td>
<td>500.</td>
</tr>
<tr>
<td>Solid</td>
<td>1,500</td>
<td>1,000.</td>
</tr>
<tr>
<td>Combinations</td>
<td>1,000y + 1,500z</td>
<td>500 (x + y) + 1,000z.</td>
</tr>
</tbody>
</table>

1 Not applicable.

Where:

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

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

z = Fraction of total heat input derived from solid fossil fuel.
(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the SO$_2$ and NO$_x$ span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring O$_2$ is selected, the measurement of the pollutant concentration and O$_2$ concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

\[
E = CF \left( \frac{20.9}{(20.9 - \%O_2)} \right)
\]

Where $E$, $C$, $F$, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO$_2$ is selected, the measurement of the pollutant concentration and CO$_2$ concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

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

Where $E$, $C$, $F_c$ and $\%CO_2$ are determined under paragraph (f) of this section.

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

(1) $E$ = pollutant emissions, ng/J (lb/MMBtu).

(2) $C$ = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by $4.15 \times 10^4$ M ng/dscm per ppm ($2.59 \times 10^{-9}$ M lb/dscf per ppm) where $M$ = pollutant molecular weight, g/g-mole (lb/lb-mole). $M = 64.07$ for SO$_2$ and $46.01$ for NO$_x$.

(3) $\%O_2$, $\%CO_2 = O_2$ or CO$_2$ volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) $F$, $F_c = \text{a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted} (F)$, and a factor representing a ratio of the volume of CO$_2$ generated to the calorific value of the fuel combusted ($F_c$), respectively. Values of $F$ and $F_c$ are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$ scm CO$_2$ /J (1,980 scf CO$_2$ /MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), $F = 2.637 \times 10^{-17}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-17}$ scm CO$_2$ /J (1,810 scf CO$_2$ /MMBtu).
(iii) For liquid fossil fuels including crude, residual, and distillate oils, \( F = 2.476 \times 10^{-7} \text{ dscm/J (9,220 dscf/MMBtu)} \) and \( F_c = 0.384 \times 10^{-7} \text{ scm CO}_2 /J (1,430\text{ scf CO}_2 /\text{MMBtu}) \).

(iv) For gaseous fossil fuels, \( F = 2.347 \times 10^{-7} \text{ dscm/J (8,740 dscf/MMBtu)} \). For natural gas, propane, and butane fuels, \( F_c = 0.279 \times 10^{-7} \text{ scm CO}_2 /J (1,040\text{ scf CO}_2 /\text{MMBtu}) \) for natural gas, \( 0.322 \times 10^{-7} \text{ scm CO}_2 /J (1,200\text{ scf CO}_2 /\text{MMBtu}) \) for propane, and \( 0.338 \times 10^{-7} \text{ scm CO}_2 /J (1,260\text{ scf CO}_2 /\text{MMBtu}) \) for butane.

(v) For bark \( F = 2.589 \times 10^{-7} \text{ dscm/J (9,640 dscf/MMBtu)} \) and \( F_c = 0.500 \times 10^{-7} \text{ scm CO}_2 /J (1,840\text{ scf CO}_2 /\text{MMBtu}) \). For wood residue other than bark \( F = 2.492 \times 10^{-7} \text{ dscm/J (9,280 dscf/MMBtu)} \) and \( F_c = 0.494 \times 10^{-7} \text{ scm CO}_2 /J (1,860\text{ scf CO}_2 /\text{MMBtu}) \).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), \( F = 2.659 \times 10^{-7} \text{ dscm/J (9,900 dscf/MMBtu)} \) and \( F_c = 0.516 \times 10^{-7} \text{ scm CO}_2 /J (1,920\text{ scf CO}_2 /\text{MMBtu}) \).

(5) The owner or operator may use the following equation to determine an \( F \) factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate \( F \) on a wet basis, consult the Administrator) or \( F_c \) factor (scm CO\(_2\)/J, or scf CO\(_2\)/MMBtu) on either basis in lieu of the \( F \) or \( F_c \) factors specified in paragraph (f)(4) of this section:

\[
F = 10^{-4} \left[ 227.2 \%H + 95.5 \%C + 33.6 \%S + 8.7 \%N - 28.7 \%O \right] / \text{GCV}
\]

\[
F_c = \frac{2.0 \times 10^3 \%C}{\text{GCV (SI units)}}
\]

\[
F = 10^{-4} \left[ 3.64 \%H + 1.53 \%C + 0.57 \%S + 0.14 \%N - 0.46 \%O \right] / \text{GCV (English units)}
\]

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

\[
F_c = \frac{321 \times 10^3 \%C}{\text{GCV (English units)}}
\]

(i) \%H, \%C, \%S, \%N, and \%O are content by weight of hydrogen, carbon, sulfur, nitrogen, and \( O_2 \) (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see § 60.17.)

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see § 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the \( F \) or \( F_c \) value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the \( F \) or \( F_c \) factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

\[
F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i
\]
Where:

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

\[ F_i \text{ or } (F_c)_i = \text{Applicable } F \text{ or } F_c \text{ factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and} \]

\[ n = \text{Number of fuels being burned in combination}. \]

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

1. **Opacity.** Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

   (i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

   (ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

2. **Sulfur dioxide.** Excess emissions for affected facilities are defined as:

   (i) For affected facilities electing not to comply with § 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO\(_2\) as measured by a CEMS exceed the applicable standard in § 60.43; or

   (ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO\(_2\) as measured by a CEMS exceed the applicable standard in § 60.43. Facilities complying with the 30-day SO\(_2\) standard shall use the most current associated SO\(_2\) compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.

3. **Nitrogen oxides.** Excess emissions for affected facilities using a CEMS for measuring NO\(_X\) are defined as:

   (i) For affected facilities electing not to comply with § 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in § 60.44; or

   (ii) For affected facilities electing to comply with § 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO\(_X\) as measured by a CEMS exceed the applicable standard in § 60.44. Facilities complying with the 30-day NO\(_X\) standard shall use the most current associated NO\(_X\) compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

4. **Particulate matter.** Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in § 60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.
(h) The owner or operator of an affected facility subject to the opacity limits in § 60.42 that elects to monitor emissions according to the requirements in § 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.


§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO2, and NOx standards in §§ 60.42, 60.43, and 60.44 as follows:

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

\[
E = CF \left( \frac{20.9}{(20.9 - \%O_2)} \right)
\]

Where:

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

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

\%O_2 = O_2 concentration, percent dry basis; and
\( F_d \) = Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the \( \%O_2 \) concentration. The \( \%O_2 \) sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the \( \%O_2 \) concentration for the run shall be the arithmetic mean of the sample \( \%O_2 \) concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the \( \%O_2 \) traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 \( \%O_2 \) traverse points.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the \( SO_2 \) concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the \( \%O_2 \) concentration. The \( \%O_2 \) sample shall be taken simultaneously with, and at the same point as, the \( SO_2 \) sample. The \( SO_2 \) emission rate shall be computed for each pair of \( SO_2 \) and \( \%O_2 \) samples. The \( SO_2 \) emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the \( NO_2 \) concentration.

(i) The sampling site and location shall be the same as for the \( SO_2 \) sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each \( NO_2 \) sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the \( \%O_2 \) concentration. The sample shall be taken simultaneously with, and at the same point as, the \( NO_2 \) sample.

(iii) The \( NO_2 \) emission rate shall be computed for each pair of \( NO_2 \) and \( \%O_2 \) samples. The \( NO_2 \) emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§ 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see § 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.
(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate \( E \) of PM, SO\(_2\) and NO\(_X\) may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate \( E \) shall be computed using the following equation:

\[
E = \frac{100 \times C}{\text{%CO}_2} \times F_c
\]

Where:

- \( E \) = Emission rate of pollutant, ng/J (lb/MMBtu);
- \( C \) = Concentration of pollutant, ng/dscm (lb/dscf);
- \( \text{%CO}_2 \) = CO\(_2\) concentration, percent dry basis; and
- \( F_c \) = Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate \( E \) and either \( E \) is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the O\(_2\) and CO\(_2\) concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if \( F_o \) (average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average \( F_o \) value, as determined from the average values of \( F_d \) and \( F_c \) in Method 19 of appendix A of this part, \( \text{t.e. } F_o = 0.209 \cdot \frac{F_{da}}{F_{ca}} \), then the following procedure shall be followed:

(A) When \( F_o < 0.97 F_{oa} \), then \( E \) shall be increased by that proportion under 0.97 \( F_{oa} \), e.g., if \( F_o \) is 0.95 \( F_{oa} \), \( E \) shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When \( F_o < 0.97 F_{oa} \) and when the average difference (d) between the continuous monitor minus the reference methods is negative, then \( E \) shall be increased by that proportion under 0.97 \( F_{oa} \), e.g., if \( F_o \) is 0.95 \( F_{oa} \), \( E \) shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When \( F_o > 1.03 F_{oa} \) and when the average difference d is positive, then \( E \) shall be decreased by that proportion over 1.03 \( F_{oa} \), e.g., if \( F_o \) is 1.05 \( F_{oa} \), \( E \) shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A-3 of this part, Method 17 of appendix A-6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used with Method 17 of appendix A-6 of this part only if it is used after wet FGD systems. Method 17 of appendix A-6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO\(_2\) may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:
(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO$_2$ (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO$_2$ emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O$_2$ concentration (%O$_2$) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]
§60.40Da Applicability and designation of affected facility.

(a) Except as specified in paragraph (e) of this section, the affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) An IGCC electric utility steam generating unit (both the stationary combustion turbine and any associated duct burners) is subject to this part and is not subject to subpart GG or KKKK of this part if both of the conditions specified in paragraphs (b)(1) and (2) of this section are met.

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

(2) The IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005.

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (i.e. heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (i.e. heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators used with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (i.e. duct burners) are subject to the standards under this
subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.


§60.41Da  Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Biomass means plant materials and animal waste.

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Boiler operating day for units constructed, reconstructed, or modified before March 1, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Combined heat and power, also known as "cogeneration," means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.
Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

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

Emission limitation means any emissions limit or operating limit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.
24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Integrated gasification combined cycle electric utility steam generating unit or IGCC electric utility steam generating unit means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (i.e., pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as “petcoke,” means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). Petroleum coke is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO2) the potential combustion concentration is determined under §60.50Da(c).

Potential electrical output capacity means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (e.g., a steam
generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity. For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Wet flue gas desulfurization technology or wet FGD means a SO₂ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.


§60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.03 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas and/or synthetic natural gas that chemically meets the definition of natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:
(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator shall not cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, the emission limits specified in paragraphs (c) or (d) of this section.

(2) During startup periods and shutdown periods, owners or operators of facilities subject to subpart UUUUU of part 63 of this chapter shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63 and use the relevant definitions in §63.10042, and owners or operators of facilities subject to subpart DDDDD of part 63 shall meet the work practice standards specified in Table 3 to subpart DDDDD of part 63 and use the relevant definition used in §63.7575.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO2 or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of §60.47Da.

§60.43Da Standards for sulfur dioxide (SO2).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain SO2 in excess of:

1. 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

2. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

3. 180 ng/J (1.4 lb/MWh) gross energy output; or

4. 65 ng/J (0.15 lb/MMBtu) heat input.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain SO2 in excess of:

1. 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

2. 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases that contain SO2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

1. Combusts 100 percent anthracite;

2. Is classified as a resource recovery unit; or

3. Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The SO2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO2 commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.
(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

1. If emissions of SO₂ to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

\[ E_s = \frac{(2.40x + 5.20y)}{100} \quad \text{and} \quad \%P_s = 10 \]

2. If emissions of SO₂ to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

\[ E_s = \frac{(2.40x + 5.20y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100} \]

Where:

- \( E_s \) = Prorated SO₂ emission limit (ng/J heat input);
- \( \%P_s \) = Percentage of potential SO₂ emission allowed;
- \( x \) = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and
- \( y \) = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO₂ in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

1. For an affected facility which commenced construction, any gases that contain SO₂ in excess of either:
   (i) 180 ng/J (1.4 lb/MWh) gross energy output; or
   (ii) 5 percent of the potential combustion concentration (95 percent reduction).

2. For an affected facility which commenced reconstruction, any gases that contain SO₂ in excess of either:
   (i) 180 ng/J (1.4 lb/MWh) gross energy output;
   (ii) 65 ng/J (0.15 lb/MMBtu) heat input; or
   (iii) 5 percent of the potential combustion concentration (95 percent reduction).

3. For an affected facility which commenced modification, any gases that contain SO₂ in excess of either:
   (i) 180 ng/J (1.4 lb/MWh) gross energy output;
   (ii) 65 ng/J (0.15 lb/MMBtu) heat input; or
   (iii) 10 percent of the potential combustion concentration (90 percent reduction).
(j) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO₂ in excess of either:

   (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

   (ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain SO₂ in excess of either:

   (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

   (ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

   (iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain SO₂ in excess of either:

   (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

   (ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

   (iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO₂ in excess of either:

   (i) 130 ng/J (1.0 lb/MWh) gross energy output; or

   (ii) 140 ng/J (1.2 lb/MWh) net energy output; or
(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO₂ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 230 ng/J (0.54 lb/MMBtu) heat input.


§60.44Da Standards for nitrogen oxides (NOX).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NOₓ (expressed as NO₂) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NOₓ in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Emission limit for heat input</th>
<th>ng/J</th>
<th>lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gaseous fuels:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal-derived fuels</td>
<td></td>
<td>210</td>
<td>0.50</td>
</tr>
<tr>
<td>All other fuels</td>
<td></td>
<td>86</td>
<td>0.20</td>
</tr>
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<td>Liquid fuels:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal-derived fuels</td>
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<td>210</td>
<td>0.50</td>
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<tr>
<td>Shale oil</td>
<td></td>
<td>210</td>
<td>0.50</td>
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<tr>
<td>All other fuels</td>
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<td>130</td>
<td>0.30</td>
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<td>Solid fuels:</td>
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<td></td>
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<tr>
<td>Coal-derived fuels</td>
<td></td>
<td>210</td>
<td>0.50</td>
</tr>
<tr>
<td>Any fuel containing more than 25%, by weight, coal refuse</td>
<td></td>
<td>(1')</td>
<td>(1')</td>
</tr>
<tr>
<td>Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace</td>
<td></td>
<td>340</td>
<td>0.80</td>
</tr>
</tbody>
</table>

[1] Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace.

[2] Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace.
<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Emission limit for heat input</th>
</tr>
</thead>
<tbody>
<tr>
<td>Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit²</td>
<td>260 ng/J, 0.60 lb/MMBtu</td>
</tr>
<tr>
<td>Subbituminous coal</td>
<td>210 ng/J, 0.50 lb/MMBtu</td>
</tr>
<tr>
<td>Bituminous coal</td>
<td>260 ng/J, 0.60 lb/MMBtu</td>
</tr>
<tr>
<td>Anthracite coal</td>
<td>260 ng/J, 0.60 lb/MMBtu</td>
</tr>
<tr>
<td>All other fuels</td>
<td>260 ng/J, 0.60 lb/MMBtu</td>
</tr>
</tbody>
</table>

¹Exempt from NOx standards and NOx monitoring requirements.

²Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (En) is determined by proration using the following formula:

$$En = \frac{(36w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NOx emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b)-(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NOx in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NOx in excess of 65 ng/J (0.15 lb/MMBtu) heat input.
(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NOx in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NOx in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NOx in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NOx (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NOx (expressed as NO2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NOx (expressed as NO2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and §60.45Da, on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NOx in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.
(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO\textsubscript{X} in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO\textsubscript{X} in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO\textsubscript{X} emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

[77 FR 9451, Feb. 16, 2012]

§60.45Da Alternative standards for combined nitrogen oxides (NO\textsubscript{X}) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO\textsubscript{X} emissions limits specified in §60.44Da may elect to meet the applicable standards for combined NO\textsubscript{X} and CO specified in paragraph (b) of this section.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO\textsubscript{X} (expressed as NO\textsubscript{2}) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO\textsubscript{X} plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO\textsubscript{X} plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO\textsubscript{X} plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

[77 FR 9453, Feb. 16, 2012]

§60.46Da [Reserved]

§60.47Da Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.
(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO₂ emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO₂ emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO₂ emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO₂ emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NOₓ emission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Pollutant</th>
<th>Equivalent electrical capacity (MW electrical output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solid solvent refined coal (SCR I)</td>
<td>SO₂</td>
<td>6,000-10,000</td>
</tr>
<tr>
<td>Fluidized bed combustion (atmospheric)</td>
<td>SO₂</td>
<td>400-3,000</td>
</tr>
<tr>
<td>Fluidized bed combustion (pressurized)</td>
<td>SO₂</td>
<td>400-1,200</td>
</tr>
<tr>
<td>Coal liquefication</td>
<td>NOₓ</td>
<td>750-10,000</td>
</tr>
<tr>
<td>Total allowable for all technologies</td>
<td></td>
<td>15,000</td>
</tr>
</tbody>
</table>

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under §60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO₂ standards or emission reduction requirements under §60.43Da but must, as a minimum, reduce SO₂ emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NOₓ standards or emission reduction requirements under §60.44Da but must, as a minimum, reduce NOₓ emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NOₓ plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Pollutant</th>
<th>Equivalent electrical capacity (MW electrical output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multi-pollutant Emission Control</td>
<td>SO₂</td>
<td>1,000</td>
</tr>
</tbody>
</table>
§60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under §60.42Da, SO2 emissions limit under §60.43Da, and NOx emissions limit under §60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO2 emissions limit under §60.43Da, NOx emissions limit under §60.44Da, and NOx plus CO emissions limit under §60.45Da apply at all times. The applicable PM emissions limit and opacity standard under §60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under §60.8, compliance with the applicable SO2 emissions limit and percentage reduction requirements under §60.43Da, NOx emissions limit under §60.44Da, and NOx plus CO emissions limit under §60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO2, NOx or NOx plus CO as applicable, and a new percent reduction for SO2 are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under §60.8, compliance with the applicable SO2 emissions limits and percentage reduction requirements under §60.43Da, the NOx emissions limits under §60.44Da, and the NOx plus CO emissions limits under §60.45Da is based on the average emission rates for SO2, NOx, CO, and percent reduction for SO2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO2 and NOx emissions limits is determined by calculating the arithmetic average of all hourly emission rates for SO2 and NOx for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO2 and NOx emissions limits is determined by dividing the sum of the SO2 and NOx emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO2 percentage reduction requirements is determined based on the average inlet and outlet SO2 emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO2 percentage reduction requirements is determined based on the “as fired” total potential emissions and the total outlet SO2 emissions for the 30 successive boiler operating days.
(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction or reconstruction commenced after May 3, 2011 that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in §60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NOx plus CO emissions limit is determined by dividing the sum of the NOx plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NOx emissions as 1.194 × 10⁻⁷ lb/scf-ppm times the average hourly NOx output concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NOx emissions may be calculated by multiplying the hourly NOx emission rate in lb/MMBtu (measured by the CEMS required under §60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(j) Compliance provisions for duct burners subject to §60.44Da(a)(1). To determine compliance with the emissions limits for NOx required by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

1. The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

2. The owner or operator of an affected duct burner may elect to determine compliance by using the CEMS specified under §60.49Da for measuring NOx and oxygen (O₂) (or carbon dioxide (CO₂)) and meet the requirements of §60.49Da. Alternatively, data from a NOx emission rate (i.e., NOx-diluent) CEMS certified according to the provisions of §75.20 of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used, with the following caveats. Data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The NOx emission rate at the outlet from the steam generating unit shall constitute the NOx emission rate from the duct burner of the combined cycle system.

(k) Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1). To determine compliance with the emission limitation for NOx required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:
(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NOx emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NOx shall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \quad [\text{Eq. 2}]$$

Where:

- $E$ = Emission rate of NOx from the duct burner, ng/J (lb/MWh) gross energy output;
- $C_{sg}$ = Average hourly concentration of NOx exiting the steam generating unit, ng/dscm (lb/dscf);
- $C_{te}$ = Average hourly concentration of NOx in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);
- $Q_{sg}$ = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);
- $Q_{te}$ = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);
- $O_{sg}$ = Average hourly gross energy output from steam generating unit, J/h (MW); and
- $h$ = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the NOx concentrations ($C_{sg}$ and $C_{te}$). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$ and $Q_{te}$) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable NOx emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NOx emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOx shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sg})}{O_{cc}} \quad [\text{Eq. 3}]$$

Where:

- $E$ = Emission rate of NOx from the duct burner, ng/J (lb/MWh) gross energy output;
- $C_{sg}$ = Average hourly concentration of NOx exiting the steam generating unit, ng/dscm (lb/dscf);
- $Q_{sg}$ = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and
O_{cc} = \text{Average hourly gross energy output from entire combined cycle unit, J/h (MW)}.

(ii) The CEMS specified under §60.49Da for measuring NOX and O2 (or CO2) shall be used to determine the average hourly NOX concentrations (C_{sg}). The continuous flow monitoring system specified in §60.49Da(l) or §60.49Da(m) shall be used to determine the volumetric flow rate (Q_{sg}) of the exhaust gas. If the option to use the flow monitoring system in §60.49Da(m) is selected, the flow rate data used to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (O_{cc}), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/h) of NOX emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NOX shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \quad (\text{Eq. 4})$$

Where:

E = \text{Emission rate of NOX from the duct burner, ng/J (lb/MWh) gross energy output};

ER_{sg} = \text{Average hourly emission rate of NOX exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu)};

H_{cc} = \text{Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h)}; and

O_{cc} = \text{Average hourly gross energy output from entire combined cycle unit, J/h (MW)}.

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NOX emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) [Reserved]

(m) Compliance provisions for sources subject to §60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO2 emissions as $1.660 \times 10^{-7}$ lb/scf-ppm times the average hourly SO2 output concentration in ppm (measured according to the provisions of §60.49Da(b)), times the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO2 emissions may be calculated by multiplying the hourly SO2 emission rate (in lb/MMBtu), measured by the CEMS required under §60.49Da, by the hourly heat input rate (measured according to the provisions of §60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.
(n) Compliance provisions for sources subject to §60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of §60.49Da(t)), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(o) Compliance provisions for sources subject to §60.42Da(c)(2), (d), or (e)(1)(ii). Except as provided for in paragraph (p) of this section, the owner or operator must demonstrate compliance with each applicable emissions limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in §60.42Da by the applicable date specified in §60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in §60.8 using the test methods and procedures in §60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated...
average opacity value for all of the test runs. If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level. In cases when a wet scrubber is used in combination with another PM control device that serves as the primary PM control device, the wet scrubber must be maintained and operated.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in §60.42Da using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in §60.42Da operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS “Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring.

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the model parameter was first determined to exceed its baseline level unless a waiver is granted by the permitting authority.
(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in §60.42Da by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the
time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 calendar days of the date that the alarm rate was first determined to exceed 5 percent limit unless a waiver is granted by the permitting authority.

(5) An owner or operator of a modified affected facility electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, evaluate, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.
(2) Each CEMS shall be installed, evaluated, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit 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. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

(q) Compliance provisions for sources subject to §60.42Da(b). An owner or operator of an affected facility subject to the opacity standard in §60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in §60.49Da(a), as applicable to the affected facility.

(r) Compliance provisions for sources subject to §60.45Da. To determine compliance with the NOx plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NOx emissions as 1.194 × 10^{-7} lb/scf-ppm times the average hourly NOx output concentration in ppm (measured according to the provisions of §60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of §60.49Da(l) or §60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of §60.49Da(u), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NOx plus CO emissions by summing the NOx emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR
60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) Notification. The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in §63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.
§60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in §60.42Da must monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (4) of this section.

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in §60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs §60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

(i) The owner or operator shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11. If during the initial 60 minutes of the observation all the 6-minute averages are less than 10 percent and all the individual 15-second observations are less than or equal to 20 percent, then the observation period may be reduced from 3 hours to 60 minutes.

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.
(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(3)(iii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a)(3)(i) of this section within 45 calendar days according to the requirements in §60.50Da(b)(3).

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations must be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(4) An owner or operator of an affected facility that is subject to an opacity standard under §60.42Da is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous and/or liquid fuels (excluding residue oil) where the potential SO2 emissions rate of each fuel is no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.51Da(d).
(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility must install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO2 emissions, except where only gaseous and/or liquid fuels (excluding residual oil) where the potential SO2 emissions rate of each fuel is 26 ng/J (0.060 lb/MMBtu) or less are combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO2 control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da, SO2 emissions are only monitored as discharged to the atmosphere.

(3) An “as fired” fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential SO2 emissions in place of a continuous SO2 emission monitor at the inlet to the SO2 control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a SO2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A CO2 or O2 continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an SO2 emission limit in lb/MMBtu under §60.43Da:

(A) When relative accuracy testing is conducted, SO2 concentration data and CO2 (or O2) data are collected simultaneously; and

(B) In addition to meeting the applicable SO2 and CO2 (or O2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of §60.51Da are met. The SO2 and, if required, CO2 (or O2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NOX emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a NOX emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility not complying with an output based limit shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring O2 or carbon dioxide (CO2) content of the flue gases at each location where SO2 or NOX emissions are monitored. For affected facilities subject to a lb/MMBtu SO2 emission limit under §60.43Da, if the owner or operator has installed and certified a CO2 or O2 monitoring system according to §75.20(c) of this chapter and appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of §75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 SO2 concentration monitoring system described in paragraph (b) of this section, to determine the SO2 emission rate in lb/MMBtu. SO2 data used to meet
the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the SO2 concentration at the same location as the SO2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the NOx concentration at the same location as the NOx monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O2 or CO2 concentration at the same location as the O2 or CO2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine O2, SO2, and NOx concentrations, respectively.

(2) SO2 or NOx (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a COMS is between 60 and 80 percent. Span values for a CEMS measuring NOx shall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, NOx span values shall be determined as follows:
Fossil fuel | Span values for NO\textsubscript{X} (ppm)
---|---
Gas | 500.
Liquid | 500.
Solid | 1,000.
Combination | 500 \((x + y) + 1,000z\).

Where:

\(x\) = Fraction of total heat input derived from gaseous fossil fuel,

\(y\) = Fraction of total heat input derived from liquid fossil fuel, and

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

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the NO\textsubscript{X} span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the SO\textsubscript{2} CEMS at the inlet to the SO\textsubscript{2} control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the SO\textsubscript{2} control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, SO\textsubscript{2} span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under §60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.
(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of “gross energy output” specified in §60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of §75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NOX standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p)-(r) [Reserved]

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.
(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limit under §60.42Da must either install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section or install, calibrate, operate, and maintain a PM CPMS according to the requirements for new facilities specified in subpart UUUUU of part 63 of this chapter. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in §60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected facility. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each PM correlation testing run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the CEMS and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and
(ii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit’s must be performed annually and Response Correlation Audits must be performed every 3 years.

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/erttool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

(w) The owner or operator using a SO₂, NOₓ, CO₂, and O₂ CEMS to meet the requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (w)(1) through (w)(5) of this section.

(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, each SO₂, NOₓ, CO₂, and O₂ CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under §60.51Da.

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required CO₂ and O₂ CEMS and for SO₂ and NOₓ CEMS with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO₂ and NOₓ span values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required CO₂ and O₂ CEMS and for SO₂ and NOₓ CEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected, the frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO₂ and NOₓ span values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For SO₂, CO₂, and O₂ CEMS and for NOₓ CEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected, the frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO₂ (regardless of the
SO\textsubscript{2} emission level during the RATA), and for NO\textsubscript{X} when the average NO\textsubscript{X} emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.


§60.50Da Compliance determination procedures and methods.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO\textsubscript{2} and NO\textsubscript{X}. Acceptable alternative methods are given in paragraph (e) of this section.

(b) In conducting the performance tests to determine compliance with the PM emissions limits in §60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in §60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O\textsubscript{2}) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 14 °C (320 25 °F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O\textsubscript{2} concentration. The O\textsubscript{2} sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O\textsubscript{2} traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O\textsubscript{2} traverse points. If the grab sampling procedure is used, the O\textsubscript{2} concentration for the run shall be the arithmetic mean of the sample O\textsubscript{2} concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO\textsubscript{2} standards in §60.43Da as follows:

(1) The percent of potential SO\textsubscript{2} emissions (%Ps) to the atmosphere shall be computed using the following equation:

\[
%P_s = \frac{(100 - %R_{\ell}) \cdot (100 - %R_{\ell})}{100}
\]
Where:

\( %Ps \) = Percent of potential SO\(_2\) emissions, percent;

\( %Rf \) = Percent reduction from fuel pretreatment, percent; and

\( %Rg \) = Percent reduction by SO\(_2\) control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction \((%Rf)\) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent SO\(_2\) reduction \((%Rg)\) of any SO\(_2\) control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the SO\(_2\) control device and the average SO\(_2\) input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in §60.49Da(b) and (d) shall be used to determine the concentrations of SO\(_2\) and CO\(_2\) or O\(_2\).

(d) The owner or operator shall determine compliance with the NO\(_X\) standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of NO\(_X\).

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of NO\(_X\) and CO\(_2\) or O\(_2\).

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B of appendix A-3 of this part, Method 17 of appendix A-6 of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after wet FGD systems. Method 17 of appendix A-6 of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The \( F_c \) factor (CO\(_2\)) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of §60.46(d)(1). The CO\(_2\) shall be determined in the same manner as the O\(_2\) concentration.

(f) The owner or operator of an electric utility combined cycle gas turbine that does not meet the definition of an IGCC must conduct performance tests for PM, SO\(_2\), and NO\(_X\) using the procedures of Method 19 of appendix A-7 of this part. The SO\(_2\) and NO\(_X\) emission rates calculations from the gas turbine used in Method 19 of appendix A-7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

§60.51Da Reporting requirements.

(a) For SO₂, NOₓ, PM, and NOₓ plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) For SO₂ and NOₓ the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average SO₂ and NOₓ emission rates (ng/J, lb/MMBtu, or lb/MWh) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) For owners or operators of affected facilities complying with the percent reduction requirement, percent reduction of the potential combustion concentration of SO₂ for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of §60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E₀*) and the upper confidence limit for the mean inlet emission rate (Eᵢ*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E₀*) and the allowable emission rate (Estd) as applicable.

(d) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) and conducting performance tests using Method 9 of appendix A-4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.
(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

(e) If fuel pretreatment credit toward the SO2 emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, SO2 or NOx emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) [Reserved]

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO2 and/or NOX and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification
statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.


§60.52Da Recordkeeping requirements.

(a) [Reserved]

(b) The owner or operator of an affected facility subject to the opacity limits in §60.42Da(b) that elects to monitor emissions according to the requirements in §60.49Da(a)(3) shall maintain records according to the requirements specified in paragraphs (b)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[74 FR 5083, Jan. 28, 2009, as amended at 77 FR 9459, Feb. 16, 2012]
Attachment D

Part 70 Operating Permit No: T129-40544-00010

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart GG—Standards of Performance for Stationary Gas Turbines

§60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.


§60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) Regenerative cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

(g) ISO standard day conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.
(h) **Efficiency** means the gas turbine manufacturer’s rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) **Peak load** means 100 percent of the manufacturer’s design capacity of the gas turbine at ISO standard day conditions.

(j) **Base load** means the load level at which a gas turbine is normally operated.

(k) **Fire-fighting turbine** means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) **Turbines employed in oil/gas production or oil/gas transportation** means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A **Metropolitan Statistical Area or MSA** as defined by the Department of Commerce.

(n) **Offshore platform gas turbines** means any stationary gas turbine located on a platform in an ocean.

(o) **Garrison facility** means any permanent military installation.

(p) **Gas turbine model** means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) **Electric utility stationary gas turbine** means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) **Emergency fuel** is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) **Unit operating hour** means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) **Excess emissions** means a specified averaging period over which either:

1. The NO\textsubscript{x} emissions are higher than the applicable emission limit in §60.332;

2. The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

3. The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) **Natural gas** means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth’s surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.
(v) **Duct burner** means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) **Lean premix stationary combustion turbine** means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) **Diffusion flame stationary combustion turbine** means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) **Unit operating day** means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.


§60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

\[
STD = 0.0075 \left( \frac{14.4}{Y} \right) + F
\]

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOx emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

\( Y \) = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of \( Y \) shall not exceed 14.4 kilojoules per watt hour, and

\( F \) = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

\[
STD = 0.0150 \left( \frac{14.4}{Y} \right) + F
\]

where:
STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO\textsubscript{X} emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

\[ Y = \text{manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of } Y \text{ shall not exceed 14.4 kilojoules per watt hour, and} \]

\[ F = \text{NO\textsubscript{X} emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.} \]

(3) The use of \( F \) in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO\textsubscript{X} allowance for fuel-bound nitrogen and determine the appropriate \( F \)-value in accordance with paragraph (a)(4) of this section or may accept an \( F \)-value of zero.

(4) If the owner or operator elects to apply a NO\textsubscript{X} emission allowance for fuel-bound nitrogen, \( F \) shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

<table>
<thead>
<tr>
<th>Fuel-bound nitrogen (percent by weight)</th>
<th>( F ) (NO\textsubscript{X} percent by volume)</th>
</tr>
</thead>
<tbody>
<tr>
<td>( N \leq 0.015 )</td>
<td>0</td>
</tr>
<tr>
<td>( 0.015 &lt; N \leq 0.1 )</td>
<td>0.04 ((N))</td>
</tr>
<tr>
<td>( 0.1 &lt; N \leq 0.25 )</td>
<td>0.004 + 0.0067((N-0.1))</td>
</tr>
<tr>
<td>( N &gt; 0.25 )</td>
<td>0.005</td>
</tr>
</tbody>
</table>

Where:

\( N = \text{the nitrogen content of the fuel (percent by weight).} \)

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the FEDERAL REGISTER.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO\textsubscript{X} emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.
(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.


§60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOx emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NOx concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:
(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO\textsubscript{X} and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO\textsubscript{X}) and a percent O\textsubscript{2} basis for oxygen; or

(ii) On a ppm at 15 percent O\textsubscript{2} basis; or

(iii) On a ppm basis (for NO\textsubscript{X}) and a percent CO\textsubscript{2} basis (for a CO\textsubscript{2} monitor that uses the procedures in Method 20 to correct the NO\textsubscript{X} data to 15 percent O\textsubscript{2}).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO\textsubscript{X} and diluent, the data acquisition and handling system must calculate and record the hourly NO\textsubscript{X} emissions in the units of the applicable NO\textsubscript{X} emission standard under §60.332(a), i.e., percent NO\textsubscript{X} by volume, dry basis, corrected to 15 percent O\textsubscript{2} and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O\textsubscript{2} concentration exceeds 19.0 percent O\textsubscript{2}, a diluent cap value of 19.0 percent O\textsubscript{2} may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H\textsubscript{o}), minimum ambient temperature (T\textsubscript{a}), and minimum combustor inlet absolute pressure (P\textsubscript{o}) into the ISO correction equation.

(iii) If the owner or operator has installed a NO\textsubscript{X} CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO\textsubscript{X} emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO\textsubscript{X} emission limit under §60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO\textsubscript{X} emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO\textsubscript{X} CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO\textsubscript{X} emissions, may, but is not required to, elect to use a NO\textsubscript{X} CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.
(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NOx emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NOx formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.

(3) For any turbine that uses SCR to reduce NOx emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NOx emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOx emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NOx emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or
(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) **Fuel oil.** For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) **Gaseous fuel.** Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) **Custom schedules.** Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples,
each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.
(iii) For turbines using NOx and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOx concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a “4-hour rolling average NOx concentration” is the arithmetic average of the average NOx concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NOx concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOx concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NOx emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) Ice fog. Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) Emergency fuel. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.
§60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NOX and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NOX concentration during the stratification test; or

(B) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NOXo) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

\[
NOX = (NOXo)(P/Po)^{0.5} e^{19 (Ho–0.00633) (288 °K/Ta)^{1.53}}
\]

Where:
\( \text{NO}_x \) = emission concentration of \( \text{NO}_x \) at 15 percent \( \text{O}_2 \) and ISO standard ambient conditions, ppm by volume, dry basis,

\( \text{NOX}_o \) = mean observed \( \text{NO}_x \) concentration, ppm by volume, dry basis, at 15 percent \( \text{O}_2 \),

\( P_r \) = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure. Alternatively, you may use 760 mm Hg (29.92 in Hg),

\( P_o \) = observed combustor inlet absolute pressure at test, mm Hg. Alternatively, you may use the barometric pressure for the date of the test,

\( H_o \) = observed humidity of ambient air, g \( \text{H}_2\text{O}/g \text{ air},

\( e \) = transcendental constant, 2.718, and

\( T_a \) = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine \( \text{NOX} \) emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable \( \text{NOX} \) emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control \( \text{NOX} \) with no additional post-combustion \( \text{NOX} \) control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 \( \text{NOX} \) emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a \( \text{NOX} \) CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable \( \text{NOX} \) emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.
(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.
(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).


§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE.

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) New stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) Reconstructed stationary RICE. (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.
(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart III, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;
(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.


§63.6595 When do I have to comply with this subpart?

(a) Affected sources. (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) Area sources that become major sources. If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.
(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.


Emission and Operating Limitations

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.


§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.
(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission requirements in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission requirements in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission requirements and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.


§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.
(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.


Testing and Initial Compliance Requirements

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.
(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.


§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.


§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.
§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

\[ \frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq. 1) \]

Where:

\( C_i \) = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

\( C_o \) = concentration of CO, THC, or formaldehyde at the control device outlet, and

\( R \) = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO₂). If pollutant concentrations are to be corrected to 15 percent oxygen and CO₂ concentration is measured in lieu of oxygen concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific \( F_o \) value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

\[ F_o = \frac{0.209 F_d}{F_c} \quad (Eq. 2) \]

Where:
F₀ = Fuel factor based on the ratio of oxygen volume to the ultimate CO₂ volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F₄₄ = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/106 Btu).

F₄₅ = Ratio of the volume of CO₂ produced to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/106 Btu)

(ii) Calculate the CO₂ correction factor for correcting measurement data to 15 percent O₂, as follows:

\[ X_{CO2} = \frac{5.9}{F₀} \quad (Eq. 3) \]

Where:

X₄₅ = CO₂ correction factor, percent.

5.9 = 20.9 percent O₂—15 percent O₂, the defined O₂ correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O₂ using CO₂ as follows:

\[ C_{adj} = C_d \times \frac{X_{CO2}}{15} \quad (Eq. 4) \]

Where:

C₄₅ = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O₂.

C₄₅ = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X₄₅ = CO₂ correction factor, percent.

%CO₂ = Measured CO₂ concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;
(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.


§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O₂ or CO₂ according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR.
part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO₂ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.
(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.
(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.
(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O2 using one of the O2 measurement methods specified in Table 4 of this subpart. Measurements to determine O2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O2 emissions simultaneously at the inlet and outlet of the control device.


Continuous Compliance Requirements

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:
(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.
(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the
engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.


Notifications, Reports, and Records

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following:

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).
(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.


§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.
(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.
(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).
(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

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

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

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.
(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE:

1. An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

2. An existing stationary emergency RICE.

3. An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

1. An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

2. An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a
site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with
the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new
stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on
an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§63.6670  Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or
tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that
agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your
U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40
CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of
the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under
§63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in
§63.6610(b).

§63.6675  What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this
part; and in this section as follows:

**Alaska Railbelt Grid** means the service areas of the six regulated public utilities that extend from Fairbanks to
Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric
Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and
the City of Seward Electric System.

**Area source** means any stationary source of HAP that is not a major source as defined in part 63.

**Associated equipment** as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment
associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to
the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions,
combustion turbines, and stationary RICE.

**Backup power for renewable energy** means an engine that provides backup power to a facility that generates
electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by
reference, see §63.14).

**Black start engine** means an engine whose only purpose is to start up a combustion turbine.

**CAA** means the Clean Air Act (42 U.S.C. 7401 et seq., as amended by Public Law 101-549, 104 Stat. 2399).
Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

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

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

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

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (e.g. biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO₂.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).
(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

**Engine startup** means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

**Four-stroke engine** means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

**Gaseous fuel** means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

**Gasoline** means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

**Glycol dehydration unit** means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

**Hazardous air pollutants (HAP)** means any air pollutants listed in or pursuant to section 112(b) of the CAA.

**Institutional emergency stationary RICE** means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

**ISO standard day conditions** means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

**Landfill gas** means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

**Lean burn engine** means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

**Limited use stationary RICE** means any stationary RICE that operates less than 100 hours per year.

**Liquefied petroleum gas** means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

**Liquid fuel** means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

**Major Source**, as used in this subpart, shall have the same meaning as in §63.2, except that:

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

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;
(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

**Malfunction** means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

**Natural gas** means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

**Non-selective catalytic reduction (NSCR)** means an add-on catalytic nitrogen oxides (NOX) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NOX, CO, and volatile organic compounds (VOC) into CO2, nitrogen, and water.

**Oil and gas production facility** as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded *(i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility *(including a building, structure, or installation)* means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

**Oxidation catalyst** means an add-on catalytic control device that controls CO and VOC by oxidation.

**Peaking unit or engine** means any standby engine intended for use during periods of high demand that are not emergencies.

**Percent load** means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

**Potential to emit** means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

**Production field facility** means those oil and gas production facilities located prior to the point of custody transfer.

**Production well** means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

**Propane** means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8.
Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.
Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

<table>
<thead>
<tr>
<th>For each  .  .  .</th>
<th>You must meet the following emission limitation, except during periods of startup  .  .  .</th>
<th>During periods of startup you must  .  .  .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 4SRB stationary RICE</td>
<td>a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or</td>
<td>Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.¹</td>
</tr>
<tr>
<td></td>
<td>b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O₂</td>
<td></td>
</tr>
</tbody>
</table>

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following operating limitation, except during periods of startup . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O\textsubscript{2} and using NSCR.</td>
<td>a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F. ¹</td>
</tr>
<tr>
<td>2. existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or existing, new and reconstructed 4SRB stationary RICE &gt;500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O\textsubscript{2} and not using NSCR.</td>
<td>Comply with any operating limitations approved by the Administrator.</td>
</tr>
</tbody>
</table>

¹Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following emission limitation, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 2SLB stationary RICE</td>
<td>a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O\textsubscript{2}. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O\textsubscript{2} until June 15, 2007</td>
<td>Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ¹</td>
</tr>
</tbody>
</table>
| 2. 4SLB stationary RICE | a. Reduce CO emissions by 93 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O\textsubscript{2} | }
For each . . . | You must meet the following emission limitation, except during periods of startup . . . | During periods of startup you must . . . 
--- | --- | --- 
3. CI stationary RICE | a. Reduce CO emissions by 70 percent or more; or |  
| b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbv or less at 15 percent O₂ |

1Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

| For each . . . | You must meet the following operating limitation, except during periods of startup . . . |  
| --- | --- | --- | 
| 1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst. | a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and |  
| b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹ |  
| 2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst | a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and |  
| b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹ |  
| 3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and | Comply with any operating limitations approved by the Administrator. |
For each . . . | You must meet the following operating limitation, except during periods of startup . . .
---|---
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.

1Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Emergency stationary CI RICE and black start stationary CI RICE</td>
<td>a. Change oil and filter every 500 hours of operation or annually, whichever comes first. b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td>Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.</td>
</tr>
<tr>
<td>2. Non-Emergency, non-black start stationary CI RICE &lt;100 HP</td>
<td>a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first. b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td></td>
</tr>
<tr>
<td>3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP</td>
<td>Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O₂.</td>
<td></td>
</tr>
<tr>
<td>For each . . .</td>
<td>You must meet the following requirement, except during periods of startup . . .</td>
<td>During periods of startup you must . . .</td>
</tr>
<tr>
<td>-------------</td>
<td>-------------------------------------------------------------------------------------------------</td>
<td>------------------------------------------</td>
</tr>
<tr>
<td>4. Non-Emergency, non-black start CI stationary RICE 300&lt;HP≤500</td>
<td>a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more.</td>
<td></td>
</tr>
<tr>
<td>5. Non-Emergency, non-black start stationary CI RICE &gt;500 HP</td>
<td>a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more.</td>
<td></td>
</tr>
<tr>
<td>6. Emergency stationary SI RICE and black start stationary SI RICE.¹</td>
<td>a. Change oil and filter every 500 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
<tr>
<td>7. Non-Emergency, non-black start stationary SI RICE &lt;100 HP that are not 2SLB stationary RICE</td>
<td>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
<tr>
<td>8. Non-Emergency, non-black start 2SLB stationary SI RICE &lt;100 HP</td>
<td>a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;² b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.³</td>
<td></td>
</tr>
</tbody>
</table>
For each . . . | You must meet the following requirement, except during periods of startup . . . | During periods of startup you must . . .
---|---|---
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500 | Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O\(_2\). |  

10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500 | Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O\(_2\). |  

11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500 | Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O\(_2\). |  

12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis | Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O\(_2\). |  

1If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

2Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

3Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]
Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
</table>
| 1. Non-Emergency, non-black start CI stationary RICE ≤300 HP   | a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first; \(^1\)  
   b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;  
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. | Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. |
| 2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500 | a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O\(_2\); or  
   b. Reduce CO emissions by 70 percent or more. | |
| 3. Non-Emergency, non-black start CI stationary RICE >500 HP | a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O\(_2\); or  
   b. Reduce CO emissions by 70 percent or more. | |
| 4. Emergency stationary CI RICE and black start stationary CI RICE.\(^2\) | a. Change oil and filter every 500 hours of operation or annually, whichever comes first; \(^1\)  
   b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and  
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. | |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must meet the following requirement, except during periods of startup . . .</th>
<th>During periods of startup you must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE &gt;500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE &gt;500 HP that operate 24 hours or less per calendar year.</td>
<td>a. Change oil and filter every 500 hours of operation or annually, whichever comes first;¹; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td>. . .</td>
</tr>
<tr>
<td>6. Non-emergency, non-black start 2SLB stationary RICE</td>
<td>a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;¹</td>
<td>. . .</td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td>. . .</td>
</tr>
<tr>
<td></td>
<td>c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td>. . .</td>
</tr>
<tr>
<td>7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP</td>
<td>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹</td>
<td>. . .</td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td>. . .</td>
</tr>
<tr>
<td></td>
<td>c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td>. . .</td>
</tr>
<tr>
<td>8. Non-emergency, non-black start 4SLB remote stationary RICE &gt;500 HP</td>
<td>a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;¹</td>
<td>. . .</td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td>. . .</td>
</tr>
<tr>
<td>For each . . .</td>
<td>You must meet the following requirement, except during periods of startup . . .</td>
<td>During periods of startup you must . . .</td>
</tr>
<tr>
<td>---------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td></td>
<td>c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td></td>
</tr>
<tr>
<td>9. Non-emergency, non-black start 4SLB stationary RICE &gt;500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year</td>
<td>Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.</td>
<td></td>
</tr>
<tr>
<td>10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP</td>
<td>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td></td>
</tr>
<tr>
<td>11. Non-emergency, non-black start 4SRB remote stationary RICE &gt;500 HP</td>
<td>a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;¹</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.</td>
<td></td>
</tr>
<tr>
<td>12. Non-emergency, non-black start 4SRB stationary RICE &gt;500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year</td>
<td>Install NSCR to reduce HAP emissions from the stationary RICE.</td>
<td></td>
</tr>
<tr>
<td>13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis</td>
<td>a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and</td>
<td></td>
</tr>
</tbody>
</table>
For each . . . | You must meet the following requirement, except during periods of startup . . . | During periods of startup you must . . .
---|---|---
| c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. |  

1Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

2If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. New or reconstructed 2SLB stationary RICE &gt;500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE &gt;500 HP located at major sources</td>
<td>Reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests semiannually.¹</td>
</tr>
<tr>
<td>2. 4SRB stationary RICE ≥5,000 HP located at major sources</td>
<td>Reduce formaldehyde emissions</td>
<td>Conduct subsequent performance tests semiannually.¹</td>
</tr>
<tr>
<td>3. Stationary RICE &gt;500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250 ≤ HP ≤ 500 located at major sources</td>
<td>Limit the concentration of formaldehyde in the stationary RICE exhaust</td>
<td>Conduct subsequent performance tests semiannually.¹</td>
</tr>
<tr>
<td>4. Existing non-emergency, non-black start CI stationary RICE &gt;500 HP that are not limited use stationary RICE</td>
<td>Limit or reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.</td>
</tr>
<tr>
<td>5. Existing non-emergency, non-black start CI stationary RICE &gt;500 HP that are limited use stationary RICE</td>
<td>Limit or reduce CO emissions and not using a CEMS</td>
<td>Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.</td>
</tr>
</tbody>
</table>

¹After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]
Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
<th>According to the following requirements . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. 2SLB, 4SLB, and CI stationary RICE</td>
<td>a. reduce CO emissions</td>
<td>i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and</td>
<td>(a) For CO and O\textsubscript{2} measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (‘3-point long line’). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at ‘3-point long line’; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(b) Measurements to determine O\textsubscript{2} must be made at the same time as the measurements for CO concentration.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>ii. Measure the O\textsubscript{2} at the inlet and outlet of the control device; and</td>
<td>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)\textsuperscript{ac} (heated probe not necessary)</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>(c) The CO concentration must be at 15 percent O\textsubscript{2}, dry basis.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Measure the CO at the inlet and the outlet of the control device</td>
<td>(1) ASTM D6522-00 (Reapproved 2005)\textsuperscript{abc} (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4</td>
<td></td>
</tr>
<tr>
<td>For each 4SRB stationary RICE</td>
<td>Complying with the requirement to reduce formaldehyde emissions</td>
<td>You must...</td>
<td>Using...</td>
<td>According to the following requirements...</td>
</tr>
<tr>
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<td>-------------------------------------------------------------</td>
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<td>------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and</td>
<td></td>
<td></td>
<td>(a) For formaldehyde, ( \mathrm{O}_2 ), and moisture measurement, ducts ( \leq 6 ) inches in diameter may be sampled at a single point located at the duct centroid and ducts ( &gt; 6 ) and ( \leq 12 ) inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is ( &gt; 12 ) inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.</td>
</tr>
<tr>
<td></td>
<td>ii. Measure ( \mathrm{O}_2 ) at the inlet and outlet of the control device; and</td>
<td>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)(^a) (heated probe not necessary)</td>
<td></td>
<td>(a) Measurements to determine ( \mathrm{O}_2 ) concentration must be made at the same time as the measurements for formaldehyde or THC concentration.</td>
</tr>
<tr>
<td></td>
<td>iii. Measure moisture content at the inlet and outlet of the control device; and</td>
<td>(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03(^a)</td>
<td></td>
<td>(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.</td>
</tr>
<tr>
<td></td>
<td>iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device</td>
<td>(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03(^a), provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent ( R ) must be greater than or equal to 70 and less than or equal to 130</td>
<td></td>
<td>(a) Formaldehyde concentration must be at 15 percent ( \mathrm{O}_2 ), dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td></td>
<td>v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device</td>
<td>(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7</td>
<td></td>
<td>(a) THC concentration must be at 15 percent ( \mathrm{O}_2 ), dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must . . .</td>
<td>Using . . .</td>
<td>According to the following requirements . . .</td>
</tr>
<tr>
<td>---------------</td>
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<td>-----------------------------------------------</td>
</tr>
<tr>
<td>3. Stationary RICE</td>
<td>a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust</td>
<td>i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and (a) For formaldehyde, CO, O2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (‘3-point long line’). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at ‘3-point long line’; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>ii. Determine the O2 concentration of the stationary RICE exhaust at the sampling port location; and (1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)(^a) (heated probe not necessary) (a) Measurements to determine O2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and (1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03(^a) (a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>iv. Measure formaldehyde at the exhaust of the stationary RICE; or (1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03(^a), provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130 (a) Formaldehyde concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>v. measure CO at the exhaust of the stationary RICE (1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)(^c), Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03(^a) (a) CO concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

**Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements**

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You have demonstrated initial compliance if . . .</th>
</tr>
</thead>
</table>
| 1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP | a. Reduce CO emissions and using oxidation catalyst, and using a CPMS | i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and  
ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and  
iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test. |
| 2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP | a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS | i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and  
ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and  
iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test. |
| 3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP | a. Reduce CO emissions and not using oxidation catalyst | i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and  
ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and  
iii. You have recorded the approved operating parameters (if any) during the initial performance test. |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You have demonstrated initial compliance if . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>4. Non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Limit the concentration of CO, and not using oxidation catalyst</td>
<td>i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the approved operating parameters (if any) during the initial performance test.</td>
</tr>
<tr>
<td>5. New or reconstructed non-emergency 2SLB stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Reduce CO emissions, and using a CEMS</td>
<td>i. You have installed a CEMS to continuously monitor CO and either O2 or CO2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.</td>
</tr>
<tr>
<td>6. Non-emergency stationary CI RICE &gt;500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE &gt;500 HP located at an area source of HAP</td>
<td>a. Limit the concentration of CO, and using a CEMS</td>
<td>i. You have installed a CEMS to continuously monitor CO and either O2 or CO2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.</td>
</tr>
<tr>
<td>7. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions and using NSCR</td>
<td>i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You have demonstrated initial compliance if . . .</td>
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<tr>
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<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and</td>
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<tr>
<td></td>
<td></td>
<td>iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.</td>
</tr>
<tr>
<td>8. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions and not using NSCR</td>
<td>i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the approved operating parameters (if any) during the initial performance test.</td>
</tr>
<tr>
<td>9. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR</td>
<td>i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.</td>
</tr>
<tr>
<td>10. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR</td>
<td>i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. You have recorded the approved operating parameters (if any) during the initial performance test.</td>
</tr>
</tbody>
</table>
| 11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP | a. Reduce CO emissions | i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
### Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP and existing non-emergency stationary CI RICE 300&lt;HP≤500 located at an area source of HAP</td>
<td>a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust</td>
<td>i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent (O_2), dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.</td>
</tr>
<tr>
<td>13. Existing non-emergency 4SLB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install an oxidation catalyst</td>
<td>i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent (O_2); ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.</td>
</tr>
<tr>
<td>14. Existing non-emergency 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install NSCR</td>
<td>i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent (O_2), or the average reduction of emissions of THC is 30 percent or more; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.</td>
</tr>
</tbody>
</table>

[78 FR 6712, Jan. 30, 2013]
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
</table>
| 2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP | a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS                        | iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and  
   v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
| 3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP | a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS | iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. |
| 4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP | a. Reduce formaldehyde emissions and using NSCR                                                      | i. Collecting the catalyst inlet temperature data according to §63.6625(b); and                     |
|                                                                                                                                   |                                                                                                         | ii. Reducing these data to 4-hour rolling averages; and                                              |
|                                                                                                                                   |                                                                                                         | iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and  
   iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. |
<table>
<thead>
<tr>
<th>For each . . .</th>
<th>Complying with the requirement to . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>5. Non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions and not using NSCR</td>
<td>i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
<tr>
<td>6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP</td>
<td>a. Reduce formaldehyde emissions</td>
<td>Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.</td>
</tr>
<tr>
<td>7. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR</td>
<td>i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
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<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</td>
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<tr>
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<td></td>
<td>v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</td>
</tr>
<tr>
<td>8. New or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP</td>
<td>a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR</td>
<td>i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
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<tr>
<td></td>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
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<tr>
<td>----------------</td>
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<td>---------------------------------------------------</td>
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<tr>
<td>9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE &lt;100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are remote stationary RICE</td>
<td>a. Work or Management practices</td>
<td>i. Operating and maintaining the stationary RICE according to the manufacturer’s emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.</td>
</tr>
<tr>
<td>10. Existing stationary CI RICE &gt;500 HP that are not limited use stationary RICE</td>
<td>a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst</td>
<td>i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</td>
</tr>
<tr>
<td>11. Existing stationary CI RICE &gt;500 HP that are not limited use stationary RICE</td>
<td>a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst</td>
<td>i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
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<tr>
<td>---------------</td>
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<td>-----------------------------------------------</td>
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<tr>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
</tr>
<tr>
<td>12. Existing limited use CI stationary RICE &gt;500 HP</td>
<td>a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst</td>
<td>i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td>ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and</td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</td>
</tr>
<tr>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
<td></td>
</tr>
<tr>
<td>13. Existing limited use CI stationary RICE &gt;500 HP</td>
<td>a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst</td>
<td>i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and</td>
</tr>
<tr>
<td></td>
<td>ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and</td>
<td>iii. Reducing these data to 4-hour rolling averages; and</td>
</tr>
<tr>
<td></td>
<td>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</td>
<td></td>
</tr>
<tr>
<td>For each . . .</td>
<td>Complying with the requirement to . . .</td>
<td>You must demonstrate continuous compliance by . . .</td>
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<tr>
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<td>----------------------------------------------------</td>
</tr>
<tr>
<td>14. Existing non-emergency 4SLB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install an oxidation catalyst</td>
<td>i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O\textsubscript{2}; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.</td>
</tr>
<tr>
<td>15. Existing non-emergency 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year</td>
<td>a. Install NSCR</td>
<td>i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O\textsubscript{2}, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.</td>
</tr>
</tbody>
</table>

- After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]
Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>For each . . .</th>
<th>You must submit a . . .</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Existing non-emergency, non-black start stationary RICE 100s≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE &gt;500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE &gt;500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE &gt;300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE &gt;500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP</td>
<td>Compliance report</td>
<td>a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or</td>
<td>i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.</td>
</tr>
<tr>
<td>2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis</td>
<td>Report</td>
<td>b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or</td>
<td>i. Semiannually according to the requirements in §63.6650(b).</td>
</tr>
<tr>
<td>3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE &gt;500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year</td>
<td>Compliance report</td>
<td>a. The results of the annual compliance demonstration, if conducted during the reporting period.</td>
<td>i. Semiannually according to the requirements in §63.6650(b)(1)-(5).</td>
</tr>
</tbody>
</table>
For each . . . | You must submit a . . . | The report must contain . . . | You must submit the report . . .
---|---|---|---
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii) | Report | a. The information in §63.6650(h)(1) | i. annually according to the requirements in §63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

<table>
<thead>
<tr>
<th>General provisions citation</th>
<th>Subject of citation</th>
<th>Applies to subpart</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>General applicability of the General Provisions</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes.</td>
<td>Additional terms defined in §63.6675.</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and abbreviations</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited activities and circumvention</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.5</td>
<td>Construction and reconstruction</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(a)</td>
<td>Applicability</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(1)-(4)</td>
<td>Compliance dates for new and reconstructed sources</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(5)</td>
<td>Notification</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(6)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(b)(7)</td>
<td>Compliance dates for new and reconstructed area sources that become major sources</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(1)-(2)</td>
<td>Compliance dates for existing sources</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(3)-(4)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(c)(5)</td>
<td>Compliance dates for existing area sources that become major sources</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(d)</td>
<td>[Reserved]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>§63.6(e)</td>
<td>Operation and maintenance</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>Applicability of standards</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(2)</td>
<td>Methods for determining compliance</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(f)(3)</td>
<td>Finding of compliance</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(g)(1)-(3)</td>
<td>Use of alternate standard</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.6(h)</td>
<td>Opacity and visible emission standards</td>
<td>No.</td>
<td>Subpart ZZZZ does not contain opacity or visible emission standards.</td>
</tr>
<tr>
<td>§63.6(i)</td>
<td>Compliance extension procedures and criteria</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>General provisions</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
</tr>
<tr>
<td>---------------------</td>
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</tr>
<tr>
<td>§63.6(j)</td>
<td>Presidential compliance exemption</td>
<td>Yes</td>
<td>Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.</td>
</tr>
<tr>
<td>§63.7(a)(1)-(2)</td>
<td>Performance test dates</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(a)(3)</td>
<td>CAA section 114 authority</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(b)(1)</td>
<td>Notification of performance test</td>
<td>Yes</td>
<td>Except that §63.7(b)(1) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(b)(2)</td>
<td>Notification of rescheduling</td>
<td>Yes</td>
<td>Except that §63.7(b)(2) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(c)</td>
<td>Quality assurance/test plan</td>
<td>Yes</td>
<td>Except that §63.7(c) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.7(d)</td>
<td>Testing facilities</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Conditions for conducting performance tests</td>
<td>No.</td>
<td>Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.</td>
</tr>
<tr>
<td>§63.7(e)(2)</td>
<td>Conduct of performance tests and reduction of data</td>
<td>Yes</td>
<td>Subpart ZZZZ specifies test methods at §63.6620.</td>
</tr>
<tr>
<td>§63.7(e)(3)</td>
<td>Test run duration</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(e)(4)</td>
<td>Administrator may require other testing under section 114 of the CAA</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(f)</td>
<td>Alternative test method provisions</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(g)</td>
<td>Performance test data analysis, recordkeeping, and reporting</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.7(h)</td>
<td>Waiver of tests</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.8(a)(1)</td>
<td>Applicability of monitoring requirements</td>
<td>Yes</td>
<td>Subpart ZZZZ contains specific requirements for monitoring at §63.6625.</td>
</tr>
<tr>
<td>§63.8(a)(2)</td>
<td>Performance specifications</td>
<td>Yes</td>
<td></td>
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<tr>
<td>§63.8(a)(3)</td>
<td>[Reserved]</td>
<td></td>
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<tr>
<td>§63.8(a)(4)</td>
<td>Monitoring for control devices</td>
<td>No.</td>
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<tr>
<td>§63.8(b)(1)</td>
<td>Monitoring</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.8(b)(2)-(3)</td>
<td>Multiple effluents and multiple monitoring systems</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)</td>
<td>Monitoring system operation and maintenance</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>Routine and predictable SSM</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(ii)</td>
<td>SSM not in Startup Shutdown Malfunction Plan</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Compliance with operation and maintenance requirements</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>§63.8(c)(2)-(3)</td>
<td>Monitoring system installation</td>
<td>Yes</td>
<td></td>
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<tr>
<td>§63.8(c)(4)</td>
<td>Continuous monitoring system (CMS) requirements</td>
<td>Yes</td>
<td>Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).</td>
</tr>
<tr>
<td>§63.8(c)(5)</td>
<td>COMS minimum procedures</td>
<td>No</td>
<td>Subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>§63.8(c)(6)-(8)</td>
<td>CMS requirements</td>
<td>Yes</td>
<td>Except that subpart ZZZZ does not require COMS.</td>
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<tr>
<td>General provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>---------------------</td>
<td>--------------------</td>
<td>-------------</td>
</tr>
<tr>
<td>§63.8(d)</td>
<td>CMS quality control</td>
<td>Yes</td>
<td>Except for §63.8(e)(5)(ii), which applies to COMS.</td>
</tr>
<tr>
<td>§63.8(e)</td>
<td>CMS performance evaluation</td>
<td>Yes</td>
<td>Except that §63.8(e) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.8(f)(1)-(5)</td>
<td>Alternative monitoring method</td>
<td>Yes</td>
<td>Except that §63.8(f)(4) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.8(f)(6)</td>
<td>Alternative to relative accuracy test</td>
<td>Yes</td>
<td>Except that §63.8(f)(6) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.8(g)</td>
<td>Data reduction</td>
<td>Yes</td>
<td>Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.</td>
</tr>
<tr>
<td>§63.9(a)</td>
<td>Applicability and State delegation of notification requirements</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.9(b)(1)-(5)</td>
<td>Initial notifications</td>
<td>Yes</td>
<td>Except that §63.9(b)(3) is reserved.</td>
</tr>
<tr>
<td>§63.9(c)</td>
<td>Request for compliance extension</td>
<td>Yes</td>
<td>Except that §63.9(c) only applies as specified in §63.6645.</td>
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<tr>
<td>§63.9(d)</td>
<td>Notification of special compliance requirements for new sources</td>
<td>Yes</td>
<td>Except that §63.9(d) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(e)</td>
<td>Notification of performance test</td>
<td>Yes</td>
<td>Except that §63.9(e) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(f)</td>
<td>Notification of visible emission (VE)/opacity test</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
</tr>
<tr>
<td>§63.9(g)(1)</td>
<td>Notification of performance evaluation</td>
<td>Yes</td>
<td>Except that §63.9(g) only applies as specified in §63.6645.</td>
</tr>
<tr>
<td>§63.9(g)(2)</td>
<td>Notification of use of COMS data</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
</tr>
<tr>
<td>§63.9(g)(3)</td>
<td>Notification that criterion for alternative to RATA is exceeded</td>
<td>Yes</td>
<td>If alternative is in use.</td>
</tr>
<tr>
<td>§63.9(h)(1)-(6)</td>
<td>Notification of compliance status</td>
<td>Yes</td>
<td>Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.</td>
</tr>
<tr>
<td>§63.9(i)</td>
<td>Adjustment of submittal deadlines</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§63.9(j)</td>
<td>Change in previous information</td>
<td>Yes</td>
<td></td>
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<tr>
<td>General provisions citation</td>
<td>Subject of citation</td>
<td>Applies to subpart</td>
<td>Explanation</td>
</tr>
<tr>
<td>------------------------------</td>
<td>-------------------------------------------------------------</td>
<td>--------------------</td>
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<tr>
<td>§63.10(a)</td>
<td>Administrative provisions for recordkeeping/reporting</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.10(b)(1)</td>
<td>Record retention</td>
<td>Yes</td>
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<tr>
<td>§63.10(b)(2)(i)-(v)</td>
<td>Records related to SSM</td>
<td>No.</td>
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<tr>
<td>§63.10(b)(2)(vi)-(xi)</td>
<td>Records</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(b)(2)(xii)</td>
<td>Record when under waiver</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(b)(2)(xiii)</td>
<td>Records when using alternative to RATA</td>
<td>Yes</td>
<td>For CO standard if using RATA alternative.</td>
</tr>
<tr>
<td>§63.10(b)(2)(xiv)</td>
<td>Records of supporting documentation</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(b)(3)</td>
<td>Records of applicability determination</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(c)</td>
<td>Additional records for sources using CEMS</td>
<td>Yes</td>
<td>Except that §63.10(c)(2)-(4) and (9) are reserved.</td>
</tr>
<tr>
<td>§63.10(d)(1)</td>
<td>General reporting requirements</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(d)(2)</td>
<td>Report of performance test results</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(d)(3)</td>
<td>Reporting opacity or VE observations</td>
<td>No</td>
<td>Subpart ZZZZ does not contain opacity or VE standards.</td>
</tr>
<tr>
<td>§63.10(d)(4)</td>
<td>Progress reports</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.10(d)(5)</td>
<td>Startup, shutdown, and malfunction reports</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.10(e)(1) and (2)(i)</td>
<td>Additional CMS Reports</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.10(e)(2)(ii)</td>
<td>COMS-related report</td>
<td>No</td>
<td>Subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>§63.10(e)(3)</td>
<td>Excess emission and parameter exceedances reports</td>
<td>Yes.</td>
<td>Except that §63.10(e)(3)(i) (C) is reserved.</td>
</tr>
<tr>
<td>§63.10(e)(4)</td>
<td>Reporting COMS data</td>
<td>No</td>
<td>Subpart ZZZZ does not require COMS.</td>
</tr>
<tr>
<td>§63.10(f)</td>
<td>Waiver for recordkeeping/reporting</td>
<td>Yes.</td>
<td></td>
</tr>
<tr>
<td>§63.11</td>
<td>Flares</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>§63.12</td>
<td>State authority and delegations</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.13</td>
<td>Addresses</td>
<td>Yes.</td>
<td></td>
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<tr>
<td>§63.14</td>
<td>Incorporation by reference</td>
<td>Yes.</td>
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<tr>
<td>§63.15</td>
<td>Availability of information</td>
<td>Yes.</td>
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</tbody>
</table>

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O₂) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O₂).

<table>
<thead>
<tr>
<th>Analyte</th>
<th>CAS No.</th>
<th>Sensitivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon monoxide (CO)</td>
<td>630-08-0</td>
<td>Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.</td>
</tr>
<tr>
<td>Oxygen (O₂)</td>
<td>7782-44-7</td>
<td></td>
</tr>
</tbody>
</table>

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O₂, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O₂ gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O₂ concentrations. The measurement system consists of the following major subsystems:
3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O₂ and moisture in the electrolyte reserve and provides a mechanism to degas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre-sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.
3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO₂ are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O₂ concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O₂; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.
6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O₂. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O₂) is acceptable for calibration of the O₂ cell. If needed, any lower percentage O₂ calibration gas must be a mixture of O₂ in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O₂ Calibration Gas Concentration.

Select an O₂ gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O₂. When the average exhaust gas O₂ readings are above 6 percent, you may use dry ambient air (20.9 percent O₂) for the up-scale O₂ calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO₂).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O₂ concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)
10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O2 for the O2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm,
whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent or ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed.

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO₂ gas standards that are generally recognized as representative of diesel-fueled engine NO and NO₂ emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO₂ interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References


(3) "ICAC Test Protocol for Periodic Monitoring", EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

Table 1: Appendix A—Sampling Run Data.

<table>
<thead>
<tr>
<th>Facility</th>
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<th>Stack Gas Sample</th>
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[78 FR 6721, Jan. 30, 2013]
What This Subpart Covers

§63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.

§63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in §63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in §63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in §63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

§63.9983  Are any fossil fuel-fired electric generating units not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a major source stationary combustion turbine subject to subpart YYYY of this part and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in §63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in §63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under subpart DDDDD of this part, if it otherwise meets the applicability provisions in that rule.

[77 FR 9464, Feb. 16, 2012, as amended at 81 FR 20180, Apr. 6, 2016]

§63.9984  When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in §63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in §63.10030 according to the schedule in §63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under §63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in §63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§63.9985  What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.
(2) An EGU that commenced reconstruction after May 3, 2011.

(b) [Reserved]


Emission Limitations and Work Practice Standards

§63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in §63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in §63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under §63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

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

(c) You may use the alternate SO2 limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and an SO2 continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO2 CEMS installed on the EGU consistent with §63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 81 FR 20180, Apr. 6, 2016]
General Compliance Requirements

§63.10000  What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements, items 3 and 4, in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with §63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section:

(A) Except as provided in paragraph (c)(1)(i)(C) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) You may pursue the LEE option provided that:

(1) Your EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or

(2) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

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

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

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

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry
flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO₂) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO₂ emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(A) You may choose to use separate sorbent trap monitoring systems to comply with this subpart: One sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods.

(B) You may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emissions limit at all times (including startup periods and shutdown periods) and to report average mercury concentration. You must follow the startup or shutdown requirements that follow and as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with §63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in §63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.
(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of §63.10010 (e.g., if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See §63.10010(a) for further details. For PM CPMS installations, follow the procedures in §63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of §63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with §63.8(c)(7)(i) and for responding to out of control periods consistent with §§63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to §63.10021(e).

(f) Except as provided under paragraph (n) of this section, you are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless your unit is a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.
(g) Except as provided under paragraph (n) of this section, if your unit no longer meets the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that your unit last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with §63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart and cease to operate in a manner that causes your unit to meet the definition of an EGU subject to this subpart, you must be in compliance with any newly applicable section 112 or 129 standards on the date you selected consistent with paragraphs (g) and (n) of this section.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source
ceases to be or becomes subject to this subpart. You must also comply with provisions of §§63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

(i) On or before the date an EGU is subject to this subpart, you must install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(m) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

(n) If you have permanently converted your EGU from coal or oil to natural gas or biomass after your compliance date (or, if applicable, after your approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents you from operating in a manner that would subject you to this subpart, you are no longer subject to this subpart, notwithstanding the coal or oil usage in the previous calendar years. The date on which you are no longer subject to this subpart is the date on which you converted to natural gas or biomass firing; it is also the date on which you must be in compliance with any newly applicable standards.


§63.10001 [Reserved]

Testing and Initial Compliance Requirements

§63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) General requirements. For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and a gross output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, e.g., hourly gross output data (megawatts); establishment of operating limits according to §63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in §63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

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

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e., an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO2 or PM CEMS, the initial performance test shall
consist of 30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90-boiler operating days. If
the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test
shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this
section. If the CMS is not certified prior to the compliance date, the test shall begin with the first operating day after
certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must
be completed on or before the date that compliance must be demonstrated (i.e., 180 days after the applicable
compliance date).

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO2 emissions
limit in Table 1 or 2 to this subpart.

(ii) You must collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO2, O2, or moisture, as
applicable) during the performance test period, in order to convert the pollutant concentrations to units of the
standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output
data during the performance test period.

(iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and
share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup
and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler operating day performance test
must either be excluded from or included in the compliance demonstration as follows:

(A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is
operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you
are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and
shutdown emissions in the compliance demonstrations;

(B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant
emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring
system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance
demonstrations; or

(C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup
or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in
the compliance demonstrations.

(b) Performance testing requirements. If you choose to use performance testing to demonstrate initial compliance
with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests
according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you
may use test data and results from a performance test conducted prior to the date on which compliance is required as
specified in §63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior
to the date on which compliance is required as specified in §63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists
of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to
this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack
flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the
EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance
test was conducted.
(6) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

(c) Operating limits. In accordance with §63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) CMS requirements. If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO₂, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO₂, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO₂, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: For this calculation, the term $E_{ij}$ in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

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

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.
(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) **Tune-ups.** All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to §63.10021(e).

(f) For an existing EGU without a neural network, a tune-up, following the procedures in §63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) **Low emitting EGUs.** The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to §63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in §63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in §63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-
boiler operating day test period. You may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO₂ or O₂) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to paragraph 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to paragraph 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to paragraph 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly gross output data (megawatts), from facility records.

(ii) If you use CEMS to measure CO₂ (or O₂) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m³ (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO₂ or O₂ concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in §63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values “C”, “Q”, “Bws” and “(MW)” with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

1. Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10⁻³ to convert it to TBtu/hr; or

2. Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10⁻³ to convert it to GW; or

3. If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).
(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) **Liquid-oil fuel moisture measurement.** If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), “Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,” or


(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177-95 (Reapproved 2010), “Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,” including Annexes A1 through A6 and Appendices X1 and X2, or


(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or
(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in §63.10030.


§63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under §63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and §63.10007 at least every year.

(b) For affected units meeting the LEE requirements of §63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

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

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

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO2 CEMS to monitor compliance with the alternate equivalent SO2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in §63.10000(c)(2)(iii).

(f) Time between performance tests. (1) Notwithstanding the provisions of §63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

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

(ii) For annual testing:

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

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

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

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

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

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

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

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

(g) If you elect to demonstrate compliance using emissions averaging under §63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10021(e).

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

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


§63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO₂, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, you must collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 to this subpart), except as otherwise provided in §63.10020(b). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii).
(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in §63.10000(c), you must also establish an operating limit according to §63.10011(b), §63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO2 ppm by $1.66 \times 10^{-7}$;

(ii) Multiply HCl ppm by $9.43 \times 10^{-8}$;

(iii) Multiply HF ppm by $5.18 \times 10^{-8}$;

(iv) Multiply HAP metals concentrations (mg/dscm) by $6.24 \times 10^{-8}$; and

(v) Multiply Hg concentrations (µg/scm) by $6.24 \times 10^{-11}$.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases,
use an equation that has the general form of Equation A-2 or A-3, replacing the value of \( K \) with \( 1.66 \times 10^{-7} \text{ lb/scf-ppm} \) for \( \text{SO}_2 \), \( 9.43 \times 10^{-6} \text{ lb/scf-ppm} \) for \( \text{HCl} \) (if an \( \text{HCl} \) CEMS is used), \( 5.18 \times 10^{-6} \text{ lb/scf-ppm} \) for \( \text{HF} \) (if an \( \text{HF} \) CEMS is used), or \( 6.24 \times 10^{-8} \text{ lb-scm/mg-scf} \) for \( \text{HAP} \) metals and for \( \text{HCl} \) and \( \text{HF} \) (when performance stack testing is used), and defining \( \text{Ch} \) as the average \( \text{SO}_2 \), \( \text{HCl} \), or \( \text{HF} \) concentration in ppm, or the average \( \text{HAP} \) metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define \( (M)_h \) as the calculated pollutant mass emission rate for the performance test (lb/h), and define \( (MW)_h \) as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the \( 10^3 \) term from Equation A-4 to determine the pollutant emission rate in lb/MW h.

(f) If you elect to (or are required to) use CEMS to continuously monitor \( \text{Hg}, \text{HCl}, \text{HF}, \text{SO}_2 \), or \( \text{PM} \) emissions (or, if applicable, sorbent trap monitoring systems to continuously collect \( \text{Hg} \) emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.

(1) \textit{Diluent cap values.} If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured \( \text{CO}_2 \) concentration is below the cap value or the measured \( \text{O}_2 \) concentration is above the cap value:

(i) For an IGCC EGU, you may use 1% for \( \text{CO}_2 \) or 19% for \( \text{O}_2 \).

(ii) For all other EGUs, you may use 5% for \( \text{CO}_2 \) or 14% for \( \text{O}_2 \).

(2) \textit{Default gross output.} If you use CEMS to continuously monitor \( \text{Hg}, \text{HCl}, \text{HF}, \text{SO}_2 \), or \( \text{PM} \) emissions (or, if applicable, sorbent trap monitoring systems to continuously collect \( \text{Hg} \) emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (i.e., combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate.

(g) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.


§63.10008 [Reserved]

§63.10009 May I use emissions averaging to comply with this subpart?

(a) General eligibility. (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of §63.9991 for filterable PM, \( \text{SO}_2 \), \( \text{HF} \), \( \text{HCl} \), non-\( \text{Hg} \) \( \text{HAP} \) metals, or \( \text{Hg} \) on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining \( \text{Hg} \) emissions) or quarterly emissions testing for demonstrating compliance.
(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the “unit designed for coal ≥ 8,300 Btu/lb” subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance (LEE) testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the “unit designed for coal ≥ 8,300 Btu/lb” subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance (LEE) testing. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) **Equations.** Use the following equations when performing calculations for your EGU emissions averaging group:

1. **Group eligibility equations.**

   \[
   WAER_m = \left[ \frac{\sum_{j=1}^{p} Herm_{j} \times Rmm_{j}}{\sum_{j=1}^{p} Rmm_{j}} + \frac{\sum_{k=1}^{m} Ter_{k} \times Rmt_{k}}{\sum_{k=1}^{m} Rmt_{k}} \right] \quad (Eq. 1a)
   \]

   Where:

   \( WAER_m \) = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

   \( Herm_{j} \) = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

   \( Rmm_{j} \) = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

   \( p \) = number of EGUs in emissions averaging group that rely on CEMS,

   \( Ter_{k} \) = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k,

   \( Rmt_{k} \) = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k, and

   \( m \) = number of EGUs in emissions averaging group that rely on emissions testing.

   \[
   WAER_m = \frac{\sum_{j=1}^{p} (Herm_{j} \times Smm_{j} \times Cfm_{j}) \times Smm_{j} \times Cfm_{j} + \sum_{k=1}^{m} Ter_{k} \times Smt_{k} \times Cft_{k}}{\sum_{j=1}^{p} Smm_{j} \times Cfm_{j} + \sum_{k=1}^{m} Smt_{k} \times Cft_{k}} \quad (Eq. 1b)
   \]

   Where:

   Variables with the similar names share the descriptions for Equation 1a of this section,
Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of this section to calculate the 30 day rolling average emissions daily.

\[
W_AER = \frac{\sum_{i=1}^{p} (H_{eri} \times R_m_i) + \sum_{i=1}^{n} (T_{eri} \times R_t_i)}{\sum_{i=1}^{p} (T_{eri} \times R_m_i) + \sum_{i=1}^{n} R_t_i} \quad (Eq. 2a)
\]

Where:

H_{eri} = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i’s CEMS for the preceding 30-group boiler operating days,

R_m_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hours that hourly rates are collected over 30-group boiler operating days,

T_{eri} = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

R_t_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

\[
W_AER = \frac{\sum_{i=1}^{p} (H_{eri} \times S_m_i \times Cfm_i) + \sum_{i=1}^{n} (T_{eri} \times S_t_i \times Cft_i)}{\sum_{i=1}^{p} (S_m_i \times Cfm_i) + \sum_{i=1}^{n} S_t_i \times Cft_i} \quad (Eq. 2b)
\]

Where:

variables with similar names share the descriptions for Equation 2a of this section,

S_m_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

S_t_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.
(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the “coal-fired unit not low rank virgin coal” subcategory. Use Equation 3a or 3b of this section to calculate the 90-day rolling average emissions daily.

\[
WAE_{IR} = \frac{\sum_{i=1}^{p} \left( \frac{\text{Her}_i \times R_{mi}}{\text{Ter}_i \times R_{ti}} \right) + \sum_{i=1}^{n} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right)}{\sum_{i=1}^{p} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right) + \sum_{i=1}^{n} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right)} \quad (Eq. 3a)
\]

Where:

\( \text{Her}_i \) = hourly emission rate from unit i’s CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

\( R_{mi} \) = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

\( p \) = number of EGUs in emissions averaging group that rely on CEMS,

\( n \) = number of hours that hourly rates are collected over the 90-group boiler operating days,

\( \text{Ter}_i \) = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

\( \text{Rt}_i \) = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

\( m \) = number of EGUs in emissions averaging group that rely on emissions testing.

\[
WAE_{IR} = \frac{\sum_{i=1}^{p} \left( \frac{\text{Her}_i \times Sm_i \times Cf_{mi}}{\text{St}_i \times Cf_{ti}} \right) + \sum_{i=1}^{n} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right)}{\sum_{i=1}^{p} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right) + \sum_{i=1}^{n} \left( \frac{\text{Ter}_i}{\text{Rt}_i} \right)} \quad (Eq. 3b)
\]

Where:

variables with similar names share the descriptions for Equation 2a of this section,

\( Sm_i \) = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

\( Cf_{mi} \) = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

\( St_i \) = steam generation in units of pounds from unit i that uses emissions testing, and

\( Cf_{ti} \) = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(c) Separate stack requirements. For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or
(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the date that you begin emissions averaging.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of paragraph (b) of this section as an alternative to using Equation 1a of paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to paragraphs (g)(1) and (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

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

(h) CEMS (or sorbent trap monitoring) use. If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) Emissions testing. If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) Emissions averaging plan. You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:
(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

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

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO$_2$, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in §63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If, as described in paragraph (f) of this section, the Administrator requests you to submit the averaging plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

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

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) **Common stack requirements.** For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in §63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.
(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.


§63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) Single unit-single stack configurations. For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) Unit(s) utilizing common stack with non-affected unit(s). (i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack. If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

(5) Unit with a common control device with multiple stack or duct configuration. If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are
discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(b) Unit with multiple parallel control devices with multiple stacks. If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O2) or carbon dioxide (CO2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O2 or CO2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O2 or CO2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).
(f)(1) If you use an SO₂ CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO₂ CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO₂ CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO₂ emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO₂ emission rates in the 30 boiler operating day period.

(4) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluent cap are available for use in the hourly SO₂ emission rate calculations, as described in §63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO₂ emission rate for any of these hours.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).
(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ±14 °C (320° ±25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:
(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in §63.8(d)(2). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in §63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any monitoring system malfunctions or out of control periods in your annual deviation reports. You must report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);

(C) Any data recorded during periods of startup or shutdown.
(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in §63.10000(c)(2)(iii) and Table 7 to this subpart.

(l) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with §63.10020(e).

1. You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

2. You shall submit the site-specific monitoring plan upon request by the Administrator.

3. The provisions of the monitoring plan must address the following items:
   (i) Monitoring system installation;
   (ii) Performance and equipment specifications;
   (iii) Schedule for initial and periodic performance evaluations;
   (iv) Performance evaluation procedures and acceptance criteria;
   (v) On-going operation and maintenance procedures; and
   (vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.


§63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with §63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS
or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in §63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with §63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO₂ or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in §63.10005(b). In all cases, the initial 30- boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with §63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO₂ or PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with §63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in §63.10031.

(4) If you choose to use paragraph (2) of the definition of “startup” in §63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of “startup” in §63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

(i) As mentioned in §63.6(g)(1), your request will be published in the FEDERAL REGISTER for notice and comment rulemaking. Until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of “startup” in §63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the FEDERAL REGISTER of the final alternative non-opacity emission standard.

(ii) Your request need not address the items contained in §63.6(g)(2).

(iii) Your request shall provide evidence of a documented manufacturer-identified safety issue.
(iv) Your request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, your request shall contain documentation that:

(A) Your EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU;

(B) You have followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) You have identified with specificity the details of your EGU manufacturer's statement of concern.

(vi) Your request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.


Continuous Compliance Requirements

§63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §§63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. You must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU.

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;
(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field’s secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup.

(ii) [Reserved]

§63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.
(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO₂, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO₂, O₂, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

\[
\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} \text{Her}_i}{n} \quad \text{(Eq. 8)}
\]

Where:

Herᵢ is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

\[
\text{30 boiler operating day average} = \frac{\sum_{i=1}^{n} \text{Hpv}_i}{n} \quad \text{(Eq. 9)}
\]

Where:

Hpvᵢ is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and
(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of §63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in §63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may perform the burner inspection any time prior to the tune-up or you may delay the first burner inspection until the next scheduled EGU outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NOx and CO must be installed within 3 calendar months after the burner inspection;

(ii) Burner or combustion control component parts that do not affect the ability to optimize NOx and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NOx. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NOx optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NOx in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NOx and O2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;
(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NOX in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in §63.10031(f)(5), until April 16, 2017. After April 16, 2017, report the date of all tune-ups electronically, in accordance with §63.10031(f). The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed.

(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.

(h) You must follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

(1) You may use the diluent cap and default gross output values, as described in §63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in §63.10031.

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

(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown.


§63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g);
(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(4) For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 to this subpart.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.


§63.10023   How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) [Reserved]

(2) Determine your operating limit as follows:

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

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

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

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

(4) If none of the steps in paragraphs (A)(1) through (3) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average \( x \) in milliamps, and the average of your corresponding three PM compliance test runs \( y \), using equation 10.
Where:

\[ \bar{x} = \frac{1}{n} \sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n} \sum_{i=1}^{n} Y_i \]  \hspace{1cm} \text{(Eq. 10)}

Xi = the PM CPMS data points for run i of the performance test,

Yi = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

\[ R = \frac{\bar{y}}{\bar{x} - z} \]  \hspace{1cm} \text{(Eq. 11)}

Where:

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

\( \bar{y} \) = the three run average PM lb/MWh,

\( \bar{x} \) = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

\[ O_L = z + \left( 0.75 \times \frac{L}{R} \right) \]  \hspace{1cm} \text{(Eq. 12)}

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.
Where:

\(X_i = \text{the PM CPMS data points for all runs } i,\)

\(n = \text{the number of data points, and}\)

\(O_h = \text{your site specific operating limit, in milliamps.}\)

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

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instrument's primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013; 81 FR 20187, Apr. 6, 2016]

Notification, Reports, and Records

§63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable.
(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10005(h)(1)(i), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) “This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance.” and

(B) “No secondary materials that are solid waste were combusted in any affected unit.”

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

(f) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit;

(2) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(3) Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits;

(4) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your request; and

(5) You maintain records of all information regarding your choice of emission limits.
(B) You begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in §63.10042.

(i) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you shall include a report that identifies:

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(iii) You may switch from paragraph (1) of the definition of “startup” in §63.10042 to paragraph (2) of the definition of “startup” (or vice-versa), provided that:

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of “startup” relied on and the proposed definition you plan to rely on;

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(C) You revise and submit all other applicable plans, e.g., monitoring and emissions averaging, with your submission;
(D) You maintain records of all information regarding your choice of the definition of “startup”; and

(E) You begin to use the revised definition of “startup” in the next reporting period after receipt of written acknowledgement from the Administrator of the switch.

(f) You must submit the notifications in §63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.


§63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §63.10021(e)(6) and (7) were completed.
(5) Should you choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for your EGU, for each instance of startup or shutdown you shall:

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of §63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of §63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) You must report emergency bypass information annually from EGUs with LEE status.

(7) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with §63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in §63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(8) A certification.

(9) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(ii)(A) or 40 CFR 71.6(a)(3)(ii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(ii)(A) or 40 CFR 71.6(a)(3)(ii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) On or after April 16, 2017, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The
electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) On or after April 16, 2017, within 60 days after the date of completing each CEMS (SO2, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in this chapter.

(2) On or after April 16, 2017, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).

(4) On or after April 16, 2017, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f) introductory text and (f)(1) through (4) of this section in paper format.

(6) Prior to April 16, 2017, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The following data elements must be entered into the ECMPS Client Tool at the time of submission of each PDF file:

(i) The facility name, physical address, mailing address (if different from the physical address), and county;

(ii) The ORIS code (or equivalent ID number assigned by EPA's Clean Air Markets Division (CAMD)) and the Facility Registry System (FRS) ID;

(iii) The EGU (or EGUs) to which the report applies. Report the EGU IDs as they appear in the CAMD Business System;
(iv) If any of the EGUs in paragraph (f)(6)(iii) of this section share a common stack, indicate which EGUs share the stack. If emissions data are monitored and reported at the common stack according to part 75 of this chapter, report the ID number of the common stack as it is represented in the electronic monitoring plan required under §75.53 of this chapter;

(v) If any of the EGUs described in paragraph (f)(6)(iii) of this section are in an averaging plan under §63.10009, indicate which EGUs are in the plan and whether it is a 30- or 90-day averaging plan;

(vi) The identification of each emission point to which the report applies. An “emission point” is a point at which source effluent is released to the atmosphere, and is either a dedicated stack that serves one of the EGUs identified in paragraph (f)(6)(iii) of this section or a common stack that serves two or more of those EGUs. To identify an emission point, associate it with the EGU or stack ID in the CAMD Business system or the electronic monitoring plan (e.g., “Unit 2 stack,” “common stack CS001,” or “multiple stack MS001”);

(vii) The rule citation (e.g., §63.10031(f)(1), §63.10031(f)(2), etc.) for which the report is showing compliance;

(viii) The pollutant(s) being addressed in the report;

(ix) The reporting period being covered by the report (if applicable);

(x) The relevant test method that was performed for a performance test (if applicable);

(xi) The date the performance test was conducted (if applicable); and

(xii) The responsible official’s name, title, and phone number.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.


§63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

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

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

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

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

(3) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).
(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

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

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

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

(e) If you elect to average emissions consistent with §63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022.

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of “startup” in §63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of “startup” in §63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum possible clean fuel capacity for each EGU;

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in §63.10020(e).

(g) You must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.
§63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.9991(a) and (b) under §63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in §63.2).

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

§63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in §63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

**Bituminous coal** means coal that is classified as bituminous according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

**Boiler operating day** means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding startup periods or shutdown periods. It is not necessary for the fuel to be combusted the entire 24-hour period.

**Capacity factor** for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

**Clean fuel** means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I (“Subpart I—Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel”).

**Coal** means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered “coal” for the purposes of this subpart.

**Coal-fired electric utility steam generating unit** means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

**Coal refuse** means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

**Cogeneration** means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

**Cogeneration unit** means a stationary, fossil fuel-fired EGU meeting the definition of “fossil fuel-fired” or stationary, integrated gasification combined cycle:

1. Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

2. Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

   i. For a topping-cycle cogeneration unit,

   (A) Useful thermal energy not less than 5 percent of total energy output; and

   (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

   ii. For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.
(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

*Combined-cycle gas stationary combustion turbine* means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue.

*Continental liquid oil-fired subcategory* means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

*Default electrical load* means an electrical load equal to 5 percent of the maximum sustainable electrical output (megawatts), as defined in section 6.5.2.1(a)(1) of Appendix A to part 75 of this chapter, of an affected EGU that is in startup or shutdown mode. For monitored common stack configurations, the default electrical load is 5 percent of the combined maximum sustainable electrical load of the EGUs that are in startup or shutdown mode during an hour in which the electrical load for all operating EGUs is zero. The default electrical load is used to calculate the electrical output-based emission rate (lb/MMBtu or lb/TBtu, as applicable) for any startup or shutdown hour in which the actual electrical load is zero. The default electrical load is not used for EGUs required to make heat input-based emission rate (lb/MMBtu or lb/TBtu, as applicable) calculations. For the purposes of this subpart, the default electrical load is not considered to be a substitute data value.

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

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

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

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

*Diluent cap* means a default CO₂ or O₂ concentration that may be used to calculate the Hg, HCl, HF, or SO₂ emission rate (lb/MMBtu or lb/TBtu, as applicable) during a startup or shutdown hour in which the measured CO₂ concentration is below the cap value or the measured O₂ concentration is above the cap value. The appropriate diluent cap values for EGUs are presented in §63.10007(f) and in section 6.2.1.2 of Appendix A to this subpart. For the purposes of this subpart, the diluent cap is not considered to be a substitute data value.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, “Standard Specification for Fuel Oils” (incorporated by reference, see §63.14).

*Dry flue gas desulfurization technology,* or *dry FGD,* or *spray dryer absorber* (SDA), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO₂ and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

*Dry sorbent injection* (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO₂ and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

*Electric Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.
Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO2 in the exhaust gas stream.

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

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of producing more than 25 MW of electrical output from the combustion of fossil fuels. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGU’s are required to evaluate applicability based on coal or oil usage from the three previous calendars years on an annual rolling basis.

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

Fluidized bed boiler, or fluidized bed combustor, or circulating fluidized boiler, or CFB means a boiler utilizing a fluidized bed combustion process.

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

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).
**Heat input** means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

**Integrated gasification combined cycle electric utility steam generating unit** or IGCC means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation. After the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

**ISO conditions** means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

**Lignite coal** means coal that is classified as lignite A or B according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

**Limited-use liquid oil-fired subcategory** means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing on the first of the month following the compliance date specified in §63.9984.

**Liquid fuel** includes, but is not limited to, distillate oil and residual oil.

**Monitoring system malfunction or out of control period** means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

**Natural gas** means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross caloric value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

**Natural gas-fired electric utility steam generating unit** means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

**Net-electric output** means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

**Neural network or neural net** for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

**Non-continental area** means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.
Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. After the first 3 years of compliance, EGU are required to evaluate applicability based on coal or oil usage from the three previous calendar years on an annual rolling basis.

Particulate matter or PM means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see §63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

Startup means:

(1) Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

(2) The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/re recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its
function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, “Standard Classification of Coals by Rank” (incorporated by reference, see §63.14).

Unit designed for coal ≥8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the “unit designed for low rank virgin coal” subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or wet FGD, or wet scrubber means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO₂ and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:

<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Coal-fired unit not low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>9.0E-2 lb/MWh&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Collect a minimum of 4 dscm per run.</td>
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<td>OR</td>
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<td>OR</td>
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<td></td>
<td>Total non-Hg HAP metals</td>
<td>6.0E-2 lb/GWh</td>
<td>Collect a minimum of 4 dscm per run.</td>
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<td></td>
<td>OR</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Individual HAP metals:</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
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</tr>
<tr>
<td></td>
<td>Arsenic (As)</td>
<td>3.0E-3 lb/GWh</td>
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<tr>
<td></td>
<td>Beryllium (Be)</td>
<td>6.0E-4 lb/GWh</td>
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<tr>
<td></td>
<td>Cadmium (Cd)</td>
<td>4.0E-4 lb/GWh</td>
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<td></td>
<td>Chromium (Cr)</td>
<td>7.0E-3 lb/GWh</td>
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<tr>
<td></td>
<td>Cobalt (Co)</td>
<td>2.0E-3 lb/GWh</td>
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<td></td>
<td>Lead (Pb)</td>
<td>2.0E-2 lb/GWh</td>
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<tr>
<td></td>
<td>Manganese (Mn)</td>
<td>4.0E-3 lb/GWh</td>
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</tr>
<tr>
<td></td>
<td>Nickel (Ni)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Selenium (Se)</td>
<td>5.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen chloride (HCl)</td>
<td>1.0E-2 lb/MWh&lt;sup&gt;1&lt;/sup&gt;</td>
<td>For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348-03&lt;sup&gt;2&lt;/sup&gt; or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sulfur dioxide (SO&lt;sub&gt;2&lt;/sub&gt;)&lt;sup&gt;2&lt;/sup&gt;</td>
<td>1.0 lb/MWh</td>
<td>SO&lt;sub&gt;2&lt;/sub&gt; CEMS.</td>
</tr>
<tr>
<td></td>
<td>c. Mercury (Hg)</td>
<td>3.0E-3 lb/GWh</td>
<td>Hg CEMS or sorbent trap monitoring system only.</td>
</tr>
<tr>
<td>2. Coal-fired units low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>9.0E-2 lb/MWh&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total non-Hg HAP metals</td>
<td>6.0E-2 lb/GWh</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
<tr>
<td>If your EGU is in this subcategory . . .</td>
<td>For the following pollutants . . .</td>
<td>You must meet the following emission limits and work practice standards . . .</td>
<td>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</td>
</tr>
<tr>
<td>------------------------------------------</td>
<td>-----------------------------------</td>
<td>---------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>3.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>6.0E-4 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>4.0E-4 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>7.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>4.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>5.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>1.0E-2 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348-032 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulfur dioxide (SO₂)²</td>
<td>1.0 lb/MWh</td>
<td>SO₂ CEMS.</td>
<td></td>
</tr>
<tr>
<td>c. Mercury (Hg)</td>
<td>4.0E-2 lb/GWh</td>
<td>Hg CEMS or sorbent trap monitoring system only.</td>
<td></td>
</tr>
<tr>
<td>3. IGCC unit</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Filterable particulate matter (PM)</td>
<td>7.0E-2 lb/MWh⁴</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>9.0E-2 lb/MWh⁵</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total non-Hg HAP metals</td>
<td>4.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>1.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>4.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>4.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
---|---|---|---
Lead (Pb) | 9.0E-3 lb/GWh | | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
Manganese (Mn) | 2.0E-2 lb/GWh | | |
Nickel (Ni) | 7.0E-2 lb/GWh | | |
Selenium (Se) | 3.0E-1 lb/GWh | | |
b. Hydrogen chloride (HCl) | 2.0E-3 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.
OR
Sulfur dioxide (SO₂)² | 4.0E-1 lb/MWh | SO₂ CEMS. |
c. Mercury (Hg) | 3.0E-3 lb/GWh | Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)
a. Filterable particulate matter (PM) | 3.0E-1 lb/MWh¹ | Collect a minimum of 1 dscm per run.
OR
OR
Total HAP metals | 2.0E-4 lb/MWh | Collect a minimum of 2 dscm per run.
OR
OR
Individual HAP metals: | | Collect a minimum of 2 dscm per run.
Antimony (Sb) | 1.0E-2 lb/GWh | |
Arsenic (As) | 3.0E-3 lb/GWh | |
Beryllium (Be) | 5.0E-4 lb/GWh | |
Cadmium (Cd) | 2.0E-4 lb/GWh | |
Chromium (Cr) | 2.0E-2 lb/GWh | |
Cobalt (Co) | 3.0E-2 lb/GWh | |
Lead (Pb) | 8.0E-3 lb/GWh | |
Manganese (Mn) | 2.0E-2 lb/GWh | |
Nickel (Ni) | 9.0E-2 lb/GWh | |
Selenium (Se) | 2.0E-2 lb/GWh | |
Mercury (Hg) | 1.0E-4 lb/GWh | For Method 30B at appendix A-8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>4.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>c. Hydrogen fluoride (HF)</td>
<td>4.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)</td>
<td>a. Filterable particulate matter (PM)</td>
<td>2.0E-1 lb/MWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total HAP metals</td>
<td>7.0E-3 lb/MWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td></td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>6.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>3.0E-1 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>3.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>1.0E-1 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>4.1E0 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mercury (Hg)</td>
<td>4.0E-4 lb/GWh</td>
<td>For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be &lt; 1/2 the standard.</td>
<td></td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-3 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>c. Hydrogen fluoride (HF)</td>
<td>5.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>6. Solid oil-derived fuel-fired unit</td>
<td>a. Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . .

<table>
<thead>
<tr>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total non-Hg HAP metals</td>
<td>6.0E-1 lb/GWh Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>8.0E-3 lb/GWh</td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>3.0E-3 lb/GWh</td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>6.0E-4 lb/GWh</td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>7.0E-4 lb/GWh</td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>6.0E-3 lb/GWh</td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>2.0E-3 lb/GWh</td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>2.0E-2 lb/GWh</td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>7.0E-3 lb/GWh</td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>4.0E-2 lb/GWh</td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>6.0E-3 lb/GWh</td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>4.0E-4 lb/MWh For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td>OR</td>
<td></td>
</tr>
<tr>
<td>Sulfur dioxide (SO₂)²</td>
<td>1.0 lb/MWh SO₂ CEMS.</td>
</tr>
<tr>
<td>c. Mercury (Hg)</td>
<td>2.0E-3 lb/GWh Hg CEMS or Sorbent trap monitoring system only.</td>
</tr>
</tbody>
</table>

Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .

¹ Gross output.

² Incorporated by reference, see §63.14.

³ You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO₂ CEMS installed.

⁴ Duct burners on syngas; gross output.

⁵ Duct burners on natural gas; gross output.

[81 FR 20190, Apr. 6, 2016]
Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:¹

<table>
<thead>
<tr>
<th>Subcategory</th>
<th>Pollutants</th>
<th>Emission Limits</th>
<th>Work Practice Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Coal-fired unit not low rank virgin coal</td>
<td>a. Filterable particulate matter (PM)</td>
<td>3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh²</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
<td>OR</td>
</tr>
<tr>
<td></td>
<td>Total non-Hg HAP metals</td>
<td>5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
<td>OR</td>
</tr>
<tr>
<td></td>
<td>Individual HAP metals:</td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Antimony (Sb)</td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Arsenic (As)</td>
<td>1.1E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Beryllium (Be)</td>
<td>2.0E-1 lb/TBtu or 2.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cadmium (Cd)</td>
<td>3.0E-1 lb/TBtu or 3.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Chromium (Cr)</td>
<td>2.8E0 lb/TBtu or 3.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cobalt (Co)</td>
<td>8.0E-1 lb/TBtu or 8.0E-3 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lead (Pb)</td>
<td>1.2E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manganese (Mn)</td>
<td>4.0E0 lb/TBtu or 5.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nickel (Ni)</td>
<td>3.5E0 lb/TBtu or 4.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Selenium (Se)</td>
<td>5.0E0 lb/TBtu or 6.0E-2 lb/GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh</td>
<td>For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03³ or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.</td>
</tr>
<tr>
<td></td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sulfur dioxide (SO₂)⁴</td>
<td>2.0E-1 lb/MMBtu or 1.5E0 lb/MWh</td>
<td>SO₂ CEMS.</td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
---|---|---|---
| c. Mercury (Hg) | 1.2E0 lb/TBtu or 1.3E-2 lb/GWh | LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only. OR
| OR | 1.0E0 lb/TBtu or 1.1E-2 lb/GWh | LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
| 2. Coal-fired unit low rank virgin coal | a. Filterable particulate matter (PM) | 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh² | Collect a minimum of 1 dscm per run. OR
| OR | OR | OR | OR
| Total non-Hg HAP metals | 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh | Collect a minimum of 1 dscm per run. OR
| OR | OR | OR | OR
<p>| Individual HAP metals: | Collect a minimum of 3 dscm per run. | | |
| Antimony (Sb) | 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh | | |
| Arsenic (As) | 1.1E0 lb/TBtu or 2.0E-2 lb/GWh | | |
| Beryllium (Be) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh | | |
| Cadmium (Cd) | 3.0E-1 lb/TBtu or 3.0E-3 lb/GWh | | |
| Chromium (Cr) | 2.8E0 lb/TBtu or 3.0E-2 lb/GWh | | |
| Cobalt (Co) | 8.0E-1 lb/TBtu or 8.0E-3 lb/GWh | | |
| Lead (Pb) | 1.2E0 lb/TBtu or 2.0E-2 lb/GWh | | |
| Manganese (Mn) | 4.0E0 lb/TBtu or 5.0E-2 lb/GWh | | |
| Nickel (Ni) | 3.5E0 lb/TBtu or 4.0E-2 lb/GWh | | |
| Selenium (Se) | 5.0E0 lb/TBtu or 6.0E-2 lb/GWh | | |</p>
<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh</td>
<td>For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A-8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulfur dioxide (SO₂)₄</td>
<td>2.0E-1 lb/MMBtu or 1.5E0 lb/MWh</td>
<td>SO₂ CEMS.</td>
<td></td>
</tr>
<tr>
<td>c. Mercury (Hg)</td>
<td>4.0E0 lb/TTBU or 4.0E-2 lb/GWh</td>
<td>LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.</td>
<td></td>
</tr>
<tr>
<td>3. IGCC unit</td>
<td>a. Filterable particulate matter (PM)</td>
<td>4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh²</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total non-Hg HAP metals</td>
<td>6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals:</td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>1.4E0 lb/TTBU or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>1.5E0 lb/TTBU or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>1.0E-1 lb/TTBU or 1.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>1.5E-1 lb/TTBU or 2.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>2.9E0 lb/TTBU or 3.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>1.2E0 lb/TTBU or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>1.9E+2 lb/TTBU or 1.8E0 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>2.5E0 lb/TTBU or 3.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>6.5E0 lb/TTBU or 7.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>2.2E+1 lb/TTBU or 3.0E-1 lb/GWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
---|---|---|---|
b. Hydrogen chloride (HCl) | 5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour. |
c. Mercury (Hg) | 2.5E0 lb/TBtu or 3.0E-2 lb/GWh | LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only. |
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units) | a. Filterable particulate matter (PM) | 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh² | Collect a minimum of 1 dscm per run. |
| | OR | OR |
| | Total HAP metals | 8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh | Collect a minimum of 1 dscm per run. |
| | OR | OR |
| | Individual HAP metals: | Collect a minimum of 1 dscm per run. |
| | Antimony (Sb) | 1.3E+1 lb/TBtu or 2.0E-1 lb/GWh |
| | Arsenic (As) | 2.8E0 lb/TBtu or 3.0E-2 lb/GWh |
| | Beryllium (Be) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh |
| | Cadmium (Cd) | 3.0E-1 lb/TBtu or 2.0E-3 lb/GWh |
| | Chromium (Cr) | 5.5E0 lb/TBtu or 6.0E-2 lb/GWh |
| | Cobalt (Co) | 2.1E+1 lb/TBtu or 3.0E-1 lb/GWh |
| | Lead (Pb) | 8.1E0 lb/TBtu or 8.0E-2 lb/GWh |
| | Manganese (Mn) | 2.2E+1 lb/TBtu or 3.0E-1 lb/GWh |
| | Nickel (Ni) | 1.1E+2 lb/TBtu or 1.1E0 lb/GWh |
| | Selenium (Se) | 3.3E0 lb/TBtu or 4.0E-2 lb/GWh |
| | Mercury (Hg) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh | For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard. |
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
---|---|---|---|
<p>| b. Hydrogen chloride (HCl) | 2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour. |
| c. Hydrogen fluoride (HF) | 4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh | For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour. |
| 5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units) | a. Filterable particulate matter (PM) | 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh² | Collect a minimum of 1 dscm per run. |
| | OR | OR | |
| | Total HAP metals | 6.0E-4 lb/MMBtu of 7.0E-3 lb/MWh | Collect a minimum of 1 dscm per run. |
| | OR | OR | |
| | Individual HAP metals: | Collect a minimum of 2 dscm per run. |
| Antimony (Sb) | 2.2E0 lb/TBtu or 2.0E-2 lb/GWh | |
| Arsenic (As) | 4.3E0 lb/TBtu or 8.0E-2 lb/GWh | |
| Beryllium (Be) | 6.0E-1 lb/TBtu or 3.0E-3 lb/GWh | |
| Cadmium (Cd) | 3.0E-1 lb/TBtu or 3.0E-3 lb/GWh | |
| Chromium (Cr) | 3.1E+1 lb/TBtu or 3.0E-1 lb/GWh | |
| Cobalt (Co) | 1.1E+2 lb/TBtu or 1.4E0 lb/GWh | |
| Lead (Pb) | 4.9E0 lb/TBtu or 8.0E-2 lb/GWh | |
| Manganese (Mn) | 2.0E+1 lb/TBtu or 3.0E-1 lb/GWh | |
| Nickel (Ni) | 4.7E+2 lb/TBtu or 4.1E0 lb/GWh | |
| Selenium (Se) | 9.8E0 lb/TBtu or 2.0E-1 lb/GWh | |
| Mercury (Hg) | 4.0E-2 lb/TBtu or 4.0E-4 lb/GWh | For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be &lt; 1/2 the standard. |</p>
<table>
<thead>
<tr>
<th>If your EGU is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>You must meet the following emission limits and work practice standards . . .</th>
<th>Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh</td>
<td>For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 2 hours.</td>
<td></td>
</tr>
<tr>
<td>c. Hydrogen fluoride (HF)</td>
<td>6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh</td>
<td>For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03 or Method 320, sample for a minimum of 2 hours.</td>
<td></td>
</tr>
<tr>
<td>6. Solid oil-derived fuel-fired unit</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. Filterable particulate matter (PM)</td>
<td>8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh²</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total non-Hg HAP metals</td>
<td>4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Individual HAP metals</td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Antimony (Sb)</td>
<td>8.0E-1 lb/TBtu or 7.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>3.0E-1 lb/TBtu or 5.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beryllium (Be)</td>
<td>6.0E-2 lb/TBtu or 5.0E-4 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>3.0E-1 lb/TBtu or 4.0E-3 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chromium (Cr)</td>
<td>8.0E-1 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cobalt (Co)</td>
<td>1.1E0 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>8.0E-1 lb/TBtu or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manganese (Mn)</td>
<td>2.3E0 lb/TBtu or 4.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nickel (Ni)</td>
<td>9.0E0 lb/TBtu or 2.0E-1 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Selenium (Se)</td>
<td>1.2E0 lb/Tbtu or 2.0E-2 lb/GWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. Hydrogen chloride (HCl)</td>
<td>5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh</td>
<td>For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03 or Method 320, sample for a minimum of 1 hour.</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . | Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . . |
---|---|---|---|
| | Sulfur dioxide (SO₂)⁴ | 3.0E-1 lb/MMBtu or 2.0E0 lb/MWh | SO₂ CEMS. |
| | c. Mercury (Hg) | 2.0E-1 lb/TBtu or 2.0E-3 lb/GWh | LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only. |

¹For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

²Gross output.

³Incorporated by reference, see §63.14.

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

[81 FR 20192, Apr. 6, 2016]

**Table 3 to Subpart UUUUU of Part 63—Work Practice Standards**

As stated in §§63.9991, you must comply with the following applicable work practice standards:

<table>
<thead>
<tr>
<th>If your EGU . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. An existing EGU</td>
<td>Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).</td>
</tr>
<tr>
<td>2. A new or reconstructed EGU</td>
<td>Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).</td>
</tr>
</tbody>
</table>
| 3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup | a. You have the option of complying using either of the following work practice standards:
(1) If you choose to comply using paragraph (1) of the definition of “startup” in §63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in §63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i). |
<table>
<thead>
<tr>
<th>If your EGU is . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2) If you choose to comply using paragraph (2) of the definition of “startup” in §63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup.</td>
<td></td>
</tr>
<tr>
<td>For startup of an EGU, you must use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in §63.10020(e).</td>
<td></td>
</tr>
<tr>
<td>Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel.</td>
<td></td>
</tr>
<tr>
<td>You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.</td>
<td></td>
</tr>
<tr>
<td>b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
<td></td>
</tr>
<tr>
<td>c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods.</td>
<td></td>
</tr>
<tr>
<td>d. You must collect monitoring data during startup periods, as specified in §63.10020(a) and (e). You must keep records during startup periods, as provided in §§63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.</td>
<td></td>
</tr>
<tr>
<td>4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown</td>
<td>You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices.</td>
</tr>
<tr>
<td>If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.</td>
<td></td>
</tr>
<tr>
<td>Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.</td>
<td></td>
</tr>
</tbody>
</table>
If your EGU is . . . | You must meet the following . . .
---|---
You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in §63.10020(a). You must keep records during shutdown periods, as provided in §§63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.

[81 FR 20196, Apr. 6, 2016]

Table 4 to Subpart UUFFFF of Part 63—Operating Limits for EGUs

As stated in §63.9991, you must comply with the applicable operating limits:

<table>
<thead>
<tr>
<th>If you demonstrate compliance using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM CPMS</td>
<td>Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of §63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).</td>
</tr>
</tbody>
</table>

[81 FR 20197, Apr. 6, 2016]

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

As stated in §63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>Using . . .</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Filterable Particulate matter (PM)</td>
<td>Emissions Testing</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at appendix A-1 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
</tr>
<tr>
<td>To conduct a performance test for the following pollutant</td>
<td>Using . . .</td>
<td>You must perform the following activities, as applicable to your input- or output-based emission limit</td>
<td>Using . . . ²</td>
</tr>
<tr>
<td>----------------------------------------------------------</td>
<td>------------</td>
<td>-------------------------------------------------</td>
<td>-------------</td>
</tr>
<tr>
<td>e. Measure the filterable PM concentration</td>
<td>Method 5 at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160° ± 14 °C (320° ± 25 °F).</td>
<td></td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

OR OR

<table>
<thead>
<tr>
<th>PM CEMS</th>
<th>Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Install, certify, operate, and maintain the PM CEMS</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
</tr>
<tr>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
</tr>
<tr>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates</td>
<td></td>
</tr>
</tbody>
</table>

2. Total or individual non-Hg HAP metals Testing

<table>
<thead>
<tr>
<th>Emissions</th>
<th>Method 1 at appendix A-1 to part 60 of this chapter.</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Select sampling ports location and the number of traverse points.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.³</td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
</tr>
<tr>
<td>e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration</td>
<td>Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.</td>
</tr>
<tr>
<td>f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
</tr>
</tbody>
</table>
To conduct a performance test for the following pollutant . . .

<table>
<thead>
<tr>
<th>Emissions Testing</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . .</th>
</tr>
</thead>
</table>
| Hydrogen chloride (HCl) and hydrogen fluoride (HF) | Using . . .

- a. Select sampling ports location and the number of traverse points. Method 1 at appendix A-1 to part 60 of this chapter.
- b. Determine velocity and volumetric flow-rate of the stack gas Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
- c. Determine oxygen and carbon dioxide concentrations of the stack gas Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.
- d. Measure the moisture content of the stack gas Method 4 at appendix A-3 to part 60 of this chapter.
- e. Measure the HCl and HF emissions concentrations Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at appendix A to part 63 of this chapter or ASTM 6348-03 with
  - (1) the following conditions when using ASTM D6348-03:
    - (A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;
    - (B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); and
    - (C) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≥ %R ≤ 130%; and

3.e.1(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

\[
\text{Reported Result} = \left( \frac{\text{Measured Concentration in Stack}}{\%R} \right) \times 10^6
\]

and

(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . . (cont'd)</th>
<th>Using . . . (cont'd)</th>
<th>You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)</th>
<th>Using . . .² (cont'd)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HCl and/or HF CEMS</td>
<td>a. Install, certify, operate, and maintain the HCl or HF CEMS</td>
<td>Appendix B of this subpart.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
</tr>
<tr>
<td>4. Mercury (Hg) Emissions Testing</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.³</td>
<td></td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>e. Measure the Hg emission concentration</td>
<td>Method 30B at appendix A-8 to part 60 of this chapter. ASTM D6784.³ or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
</tr>
<tr>
<td>OR</td>
<td>OR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hg CEMS</td>
<td>a. Install, certify, operate, and maintain the CEMS</td>
<td>Sections 3.2.1 and 5.1 of appendix A of this subpart.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
<td></td>
</tr>
<tr>
<td>To conduct a performance test for the following pollutant . . . (cont'd)</td>
<td>Using . . . (cont'd)</td>
<td>You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont'd)</td>
<td>Using . . .² (cont'd)</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates</td>
<td>Section 6 of appendix A to this subpart.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sorbent trap monitoring system</td>
<td>a. Install, certify, operate, and maintain the sorbent trap monitoring system</td>
<td>Sections 3.2.2 and 5.2 of appendix A to this subpart.</td>
<td></td>
</tr>
<tr>
<td>b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems</td>
<td>Part 75 of this chapter and §63.10010(a), (b), (c), and (d).</td>
<td></td>
<td></td>
</tr>
<tr>
<td>c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates</td>
<td>Section 6 of appendix A to this subpart.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OR OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LEE testing</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>c. Determine oxygen and carbon dioxide concentrations of the stack gas</td>
<td>Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,³ or diluent gas monitoring systems certified according to part 75 of this chapter.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>e. Measure the Hg emission concentration</td>
<td>Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (i.e., per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates</td>
<td>Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
To conduct a performance test for the following pollutant . . . (cont’d)

Using . . . (cont’d)

You must perform the following activities, as applicable to your input- or output-based emission limit . . . (cont’d)

Using . . . ² (cont’d)

g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold

Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

5. Sulfur dioxide (SO₂)

SO₂ CEMS

a. Install, certify, operate, and maintain the CEMS

Part 75 of this chapter and §63.10010(a) and (f).

b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems

Part 75 of this chapter and §63.10010(a), (b), (c), and (d).

c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates

Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see §63.10007(e)).

¹Regarding emissions data collected during periods of startup or shutdown, see §§63.10020(b) and (c) and 63.10021(h).

²See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

³Incorporated by reference, see §63.14.

[81 FR 20197, Apr. 6, 2016]

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

As stated in §63.10007, you must comply with the following requirements for establishing operating limits:

<table>
<thead>
<tr>
<th>If you have an applicable emission limit for . . .</th>
<th>And you choose to establish PM CPMS operating limits, you must . . .</th>
<th>And . . .</th>
<th>Using . . .</th>
<th>According to the following procedures . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU</td>
<td>Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to §63.10010(h)(1)</td>
<td>Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal)</td>
<td>Data from the PM CPMS and the PM or HAP metals performance tests</td>
<td>1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of §63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.</td>
</tr>
</tbody>
</table>
Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in §63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

<table>
<thead>
<tr>
<th>If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .</th>
<th>You demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. CEMS to measure filterable PM, SO₂, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg</td>
<td>Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.</td>
</tr>
<tr>
<td>2. PM CPMS to measure compliance with a parametric operating limit</td>
<td>Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.</td>
</tr>
<tr>
<td>3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring</td>
<td>If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.</td>
</tr>
<tr>
<td>4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2</td>
<td>Calculating the results of the testing in units of the applicable emissions standard.</td>
</tr>
<tr>
<td>5. Conducting periodic performance tune-ups of your EGU(s)</td>
<td>Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).</td>
</tr>
<tr>
<td>6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup</td>
<td>Operating in accordance with Table 3.</td>
</tr>
<tr>
<td>7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown</td>
<td>Operating in accordance with Table 3.</td>
</tr>
</tbody>
</table>

[78 FR 24092, Apr. 24, 2013]

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

As stated in §63.10031, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>You must submit a</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.10031(c)(1) through (9); and</td>
<td>Semiannually according to the requirements in §63.10031(b).</td>
</tr>
</tbody>
</table>
You must submit a

The report must contain . . .

You must submit the report . . .

b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and

c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.10031(e).

[81 FR 20201, Apr. 6, 2016]

Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

As stated in §63.10040, you must comply with the applicable General Provisions according to the following:

<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Applies to subpart UUUUU</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>Applicability</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes. Additional terms defined in §63.10042.</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and Abbreviations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited Activities and Circumvention</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.5</td>
<td>Preconstruction Review and Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j)</td>
<td>Compliance with Standards and Maintenance Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(e)(1)(i)</td>
<td>General Duty to minimize emissions</td>
<td>No. See §63.10000(b) for general duty requirement.</td>
</tr>
<tr>
<td>§63.6(e)(1)(ii)</td>
<td>Requirement to correct malfunctions ASAP</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(e)(3)</td>
<td>SSM Plan requirements</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>SSM exemption</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(h)(1)</td>
<td>SSM exemption</td>
<td>No.</td>
</tr>
<tr>
<td>Citation</td>
<td>Subject</td>
<td>Applies to subpart UUUUU</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------------------------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>§63.6(g)</td>
<td>Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard</td>
<td>Yes. See §§63.10011(g)(4) and 63.10021(h)(4) for additional requirements.</td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Performance testing</td>
<td>No. See §63.10007.</td>
</tr>
<tr>
<td>§63.8</td>
<td>Monitoring Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>General duty to minimize emissions and CMS operation</td>
<td>No. See §63.10000(b) for general duty requirement.</td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Requirement to develop SSM Plan for CMS</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(d)(3)</td>
<td>Written procedures for CMS</td>
<td>Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.</td>
</tr>
<tr>
<td>§63.9</td>
<td>Notification Requirements</td>
<td>Yes, except (1) for the 60-day notification prior to conducting a performance test in §63.9(e); instead use a 30-day notification period per §63.10030(d), (2) the notification of the CMS performance evaluation in §63.9(g)(1) is limited to RATAs, and (3) the information required per §63.9(h)(2)(i); instead provide the information required per §63.10030(e)(1) through (e)(6) and (e)(8).</td>
</tr>
<tr>
<td>§63.10(a), (b)(1), (c), (d)(1) and (2), (e), and (f)</td>
<td>Recordkeeping and Reporting Requirements</td>
<td>Yes, except for the requirements to submit written reports under §63.10(e)(3)(v).</td>
</tr>
<tr>
<td>§63.10(b)(2)(i)</td>
<td>Recordkeeping of occurrence and duration of startups and shutdowns</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(ii)</td>
<td>Recordkeeping of malfunctions</td>
<td>No. See §63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iii)</td>
<td>Maintenance records</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iv)</td>
<td>Actions taken to minimize emissions during SSM</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(v)</td>
<td>Actions taken to minimize emissions during SSM</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vi)</td>
<td>Recordkeeping for CMS malfunctions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vii) through (ix)</td>
<td>Other CMS requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(3) and (d)(3) through (5)</td>
<td>Other CMS requirements</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(c)(7)</td>
<td>Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions</td>
<td>Yes.</td>
</tr>
<tr>
<td>Citation</td>
<td>Subject</td>
<td>Applies to subpart UUUUU</td>
</tr>
<tr>
<td>---------------</td>
<td>-------------------------------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>§63.10(c)(8)</td>
<td>Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(10)</td>
<td>Recording nature and cause of malfunctions</td>
<td>No. See §63.10032(g) and (h) for malfunctions recordkeeping requirements.</td>
</tr>
<tr>
<td>§63.10(c)(11)</td>
<td>Recording corrective actions</td>
<td>No. See §63.10032(g) and (h) for malfunctions recordkeeping requirements.</td>
</tr>
<tr>
<td>§63.10(c)(15)</td>
<td>Use of SSM Plan</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(5)</td>
<td>SSM reports</td>
<td>No. See §63.10021(h) and (i) for malfunction reporting requirements.</td>
</tr>
<tr>
<td>§63.11</td>
<td>Control Device Requirements</td>
<td>No.</td>
</tr>
<tr>
<td>§63.12</td>
<td>State Authority and Delegation</td>
<td>Yes.</td>
</tr>
<tr>
<td>§§63.13 through 63.16</td>
<td>Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§§63.1(a)(5),(a)(7) through (9), (b)(2), (c)(3) and (4), (d), 63.6(b)(6), (c)(3) and (4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through (4), (c)(9).</td>
<td>Reserved</td>
<td></td>
</tr>
</tbody>
</table>

[81 FR 20202, Apr. 6, 2016]

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions


1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.
1.4 Missing Data Procedures. The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 Monitoring System Installation Requirements. Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, §63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 Primary and Backup Monitoring Systems. In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, i.e., when the system is “in control”. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 Redundant Backup Systems. A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on “hot standby” in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 Non-redundant Backup Monitoring Systems. A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on “cold standby” and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 Temporary Like-kind Replacement Analyzers. When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix “LK”.

2.2.4 Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers. To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.
2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg0, CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 Definitions.

3.1.1 Mercury Continuous Emission Monitoring System or Hg CEMS means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg$^{+2}$ to Hg0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 Sorbent Trap Monitoring System means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter ($\mu$g/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 NIST means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 NIST-Traceable Elemental Hg Standards means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards”; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the “EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators” or an interim version of that protocol.

3.1.5 NIST-Traceable Source of Oxidized Hg means a generator that is capable of providing known concentrations of vapor phase mercuric chloride (HgCl2), and that meets the performance requirements of the “EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators” or an interim version of that protocol.

3.1.6 Calibration Gas means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 Span Value means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 Zero-Level Gas means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 Low-Level Gas means calibration gas with a concentration that is 20 to 30 percent of the span value.
3.1.10 Mid-Level Gas means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 High-Level Gas means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 Calibration Error Test means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 Linearity Check means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 System Integrity Check means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 Cycle Time Test means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 Relative Accuracy Test Audit or RATA means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 Unit Operating Hour means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 Stack Operating Hour means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 Operating Day means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance (QA) Operating Quarter means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 Grace Period means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 Continuous Monitoring Methods.

3.2.1 Hg CEMS. A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.
3.2.1.1 Equipment Specifications.

3.2.1.1.1 Materials of Construction. All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 Temperature Considerations. All system components prior to the Hg$^{2+}$ to Hg$^{0}$ converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 Measurement System Components.

3.2.1.1.3.1 Sample Probe. The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 Filter or Other Particulate Removal Device. The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 Sample Line. The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 Conditioning Equipment. For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 Sampling Pump. A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.
3.2.1.3.6 **Calibration Gas System(s).** Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and HgCl₂ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.3.7 **Sample Gas Delivery.** The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.3.8 **Hg Analyzer.** An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.3.9 **Data Recorder.** A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 **Reagents and Standards.**

3.2.1.2.1 **NIST Traceability.** Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg⁰ and HgCl₂ are required. Special reagents and equipment may be needed to prepare the Hg⁰ and HgCl₂ gas standards (e.g., NIST-traceable solutions of HgCl₂ and gas generators equipped with mass flow controllers).

3.2.1.2.2 **Required Calibration Gas Concentrations.**

3.2.1.2.2.1 **Zero-Level Gas.** A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 **Low-Level Gas.** A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks, and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 **Mid-Level Gas.** A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 **High-Level Gas.** A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 **Installation and Measurement Location.** For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO₂ or O₂ monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 **Monitor Span and Range Requirements.** Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 **Maximum Potential Concentration.** There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 µg/scm for all coal
ranks (including coal refuse) except for lignite; for lignite, use 16 µg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (i.e., the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 Span Value. To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

3.2.1.4.3 Analyzer Range. The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 Sorbent Trap Monitoring System. A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 Other Necessary Data Collection. To convert measured hourly Hg concentrations to the units of the applicable emissions standard (i.e., lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 Heat Input-Based Emission Limits. For a heat input-based Hg emission limit (i.e., in lb/TBtu), data from a certified CO₂ or O₂ monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 Electrical Output-Based Emission Rates. If the applicable Hg limit is electrical output-based (i.e., lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 Sorbent Trap Monitoring System Operation. Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 Certification Requirements. All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in §63.9984(f).

4.1.1 Hg CEMS. Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (i.e., combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 7-Day Calibration Error Test. Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in paragraphs
3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in paragraphs 3.1.4 of this appendix) for the test. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. If moisture is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (i.e., resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.2 Linearity Check. Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 Three-Level System Integrity Check. Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

<table>
<thead>
<tr>
<th>For this required certification test</th>
<th>The main performance specification</th>
<th>The alternate performance specification</th>
<th>And the conditions of the alternate specification are</th>
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<td>7-day calibration error test&lt;sup&gt;26&lt;/sup&gt;</td>
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<tr>
<td>RATA</td>
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</tbody>
</table>

Table A-1—Required Certification Tests and Performance Specifications for Hg CEMS

1. For this certification test,
2. The main performance specification is,
3. The alternate performance specification is,
4. And the conditions of the alternate specification are,
5. The alternate specification may be used on any day of the test.
6. The alternate specification may be used at any gas level.
7. The alternate specification may be used at any gas level.
For this required certification test . . . 
The main performance specification is . . . 
The alternate performance specification is . . . 
And the conditions of the alternate specification are . . . 

| Cycle time test | 15 minutes where the stability criteria are readings change by < 2.0% of span or by ≤ 0.5 µg/scm, for 2 minutes. |

1 Note that \(|R - A|\) is the absolute value of the difference between the reference gas value and the analyzer reading. 
\(|R - A_{avg}|\) is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

2 Use elemental Hg standards; a mid-level or high-level upscale gas may be used.

3 Use elemental Hg standards.

4 Use oxidized Hg standards.

5 Use elemental Hg standards; a high-level upscale gas must be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitoring systems must be capable of recording at least one Hg concentration reading every 15 minutes.

6 If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

7 Note that \(|R_{avg} - C_{avg}|\) is the absolute difference between the mean reference method value and the mean CEMS value from the RATA; \(CC\) is the confidence coefficient from Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter.

4.1.1.4 Cycle Time Test. Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 Relative Accuracy Test Audit (RATA). Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60 of this chapter. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

\[
RD = \frac{|C_a - C_i|}{C_a + C_i} \times 100 \quad \text{(Eq. A - 1)}
\]
Where:

\[ RD = \text{Relative Deviation between the Hg concentrations of samples "a" and "b" (percent),} \]
\[ C_a = \text{Hg concentration of Hg sample "a" (µg/dscm),} \]
\[ C_b = \text{Hg concentration of Hg sample "b" (µg/dscm).} \]

4.1.1.5.1 **Special Considerations.** A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)” (incorporated by reference, see §63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 **Calculation of RATA Results.** Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2-6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1 of this appendix.

4.1.1.5.3 **Bias Adjustment.** Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 **Sorbent Trap Monitoring Systems.** For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 **Reference Methods.** The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 “The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;
4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤20% of section 1 Hg mass;
4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤50% of section 1 Hg mass; and
4.1.2.2.4 For stack Hg concentrations ≤0.1 µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 **Calculation of RATA Results.** Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the
reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 Bias Adjustment. Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems. Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 Recertification. Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. ONGOING QUALITY ASSURANCE (QA) AND DATA VALIDATION

5.1 Hg CEMS.

5.1.1 Required QA Tests. Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (i.e., combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 Test Frequency. The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases for the 7-day calibration error test (or the daily calibration error check) until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for “non-QA operating quarters”. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 Perform a single-level system integrity check weekly, i.e., once every 7 operating days (see the third column in Table A-2 of this appendix).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, i.e., once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a
required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 Grace Periods.

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 Data Validation. The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 Conditional Data Validation. For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

Table A-2—On-Going QA Test Requirements for Hg CEMS

<table>
<thead>
<tr>
<th>Perform this type of QA test . . .</th>
<th>At this frequency . . .</th>
<th>With these qualifications and exceptions . . .</th>
<th>Acceptance criteria . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calibration error test</td>
<td>Daily</td>
<td>• Use either a mid- or high-level gas</td>
<td>$</td>
</tr>
<tr>
<td>Single-level system integrity check</td>
<td>Weekly$^1$</td>
<td>• Use oxidized Hg—either mid- or high-level</td>
<td>$</td>
</tr>
<tr>
<td>Linearity check or 3-level system integrity check</td>
<td>Quarterly$^3$</td>
<td>• Required in each “QA operating quarter” and no less than once every 4 calendar quarters</td>
<td>$</td>
</tr>
<tr>
<td>RATA</td>
<td>Annual$^4$</td>
<td>• Test deadline may be extended for “non-QA operating quarters,” up to a maximum of 8 quarters from the quarter of the previous test.</td>
<td>$</td>
</tr>
</tbody>
</table>

$^1$“Weekly” means once every 7 operating days.

$^2$A “QA operating quarter” is a calendar quarter with at least 168 unit or stack operating hours.
“Quarterly” means once every QA operating quarter.

“Annual” means once every four QA operating quarters.

If your Hg CEMS lacks an integrated elemental Hg gas generator, you may continue to use NIST-traceable oxidized Hg gases until such time as NIST-traceable compressed elemental Hg gas standards, at appropriate concentration levels, are available from gas vendors.

5.1.6 Adjustment of Span. If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 Sorbent Trap Monitoring Systems.

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, i.e., once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 Flow Rate, Diluent Gas, and Moisture Monitoring Systems. The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§63.10010(b) through (d)).

5.4 QA/QC Program Requirements. The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 General Requirements.

5.4.1.1 Preventive Maintenance. Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 Recordkeeping and Reporting. Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.
5.4.1.3 Maintenance Records. Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 Specific Requirements for Hg CEMS.

5.4.2.1 Daily Calibrations, Linearity Checks and System Integrity Checks. Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 Monitoring System Adjustments. Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 Relative Accuracy Test Audits. Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 Specific Requirements for Sorbent Trap Monitoring Systems.

5.4.3.1 Sorbent Trap Identification and Tracking. Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 Monitoring System Integrity and Data Quality. Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 Hg Analysis. Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 Data Collection Period. State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 Relative Accuracy Test Audit Procedures. Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. DATA REDUCTION AND CALCULATIONS

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with §60.13(h)(2) of this chapter.
6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and
assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter
used in the emissions calculations (i.e., flow rate, diluent gas concentration, or moisture, as applicable), do not
calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not
considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of
monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 Calculation of Hg Emission Rates. Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this
section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 Heat Input-Based Hg Emission Rates. Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu,
according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in
appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg
concentration value by $6.24 \times 10^{-11}$ to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not
listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this
chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for
startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified
in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control
and the hourly average O₂ concentration is above 14.0% O₂ (19.0% for an IGCC) or the hourly average CO₂
concentration is below 5.0% CO₂ (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10⁶ to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating
day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to
calculate the Hg emission rate for each averaging period. The term $E_{hj}$ in Equation 19-19 must be in the units of the
applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 Electrical Output-Based Hg Emission Rates. Calculate electrical output-based Hg emission limits in units of
lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters,
using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section
(for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h$$  \hspace{1cm} \text{(Equation A-2)}

Where:

$M_h$ = Hg mass emission rate for the hour (lb/h)

$K$ = Units conversion constant, $6.24 \times 10^{-11}$ lb-scm/µg-scf,

$C_h$ = Hourly average Hg concentration, wet basis (µg/scm)

$Q_h$ = Stack gas volumetric flow rate for the hour (scfh).

(NOTE: Use unadjusted flow rate values; bias adjustment is not required)
\[ M_h = K C_h Q_h \left(1 - B_{ws}\right) \]  
\text{(Equation A-3)}

Where:

- \( M_h \) = Hg mass emission rate for the hour (lb/h)
- \( K \) = Units conversion constant, \( 6.24 \times 10^{-11} \) lb-scm/µg-scf.
- \( C_h \) = Hourly average Hg concentration, dry basis (µg/dscm).
- \( Q_h \) = Stack gas volumetric flow rate for the hour (scfh)

(Note: Use unadjusted flow rate values; bias adjustment is not required).

\( B_{ws} \) = Moisture fraction of the stack gas, expressed as a decimal (equal to % H₂O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

\[ E_{ho} = \frac{M_h}{(MW)_h} \times 10^3 \]  
\text{(Equation A-4)}

Where:

- \( E_{ho} \) = Electrical output-based Hg emission rate (lb/GWh).
- \( M_h \) = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).
- \( (MW)_h \) = Gross electrical load for the hour, in megawatts (MW).

\( 10^3 \) = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation A-5 of this appendix to calculate the Hg emission rate for each averaging period.

\[ E_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \]  
\text{(Eq. A - 5)}

Where:

- \( E_o \) = Hg emission rate for the averaging period (lb/GWh),
- \( E_{ho} \) = Gross output-based hourly Hg emission rate for unit or stack sampling hour “h” in the averaging period, from Equation A-4 of this appendix (lb/GWh), and
- \( n \) = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters. (Note: Do not include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 Recordkeeping Provisions. For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the
date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 7.1.1 through
7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or
operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and
any other monitoring system(s) (i.e., flow rate, diluent gas, or moisture systems) needed for routine operation of a
sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The
monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how
the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified
continuous monitoring system that is used to provide data under this subpart (including a change in the automated
data acquisition and handling system or the flue gas handling system) which affects information reported in the
monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator
shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan
shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow
rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for
those systems under §75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s);
monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not
limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring
equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range
information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and
Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric
Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg
monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations;
miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating
hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are
needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only
the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load,
record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can
range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in §63.10042).

7.1.2.6 The EGUs that constitute an emissions averaging group.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or
operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;
7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.4 Hg Emissions Records (Sorbent Trap Monitoring Systems). For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.5 Stack Gas Volumetric Flow Rate Records.

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

7.1.6 Records of Stack Gas Moisture Content.

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:
7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from §75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

7.1.7 Records of Diluent Gas (CO₂ or O₂) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO₂ or O₂ concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO₂ or O₂ concentration records, as specified in §75.57(g) of this chapter.

7.1.8 Hg Emission Rate Records. For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.8.5 If applicable, a code to indicate that the default gross output (as defined in §63.10042) was used to calculate the Hg emission rate.

7.1.8.6 If applicable, a code to indicate that the diluent cap (as defined in §63.10042) was used to calculate the Hg emission rate.

7.1.9 Certification and Quality Assurance Test Records. For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;
7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in §75.59 of this chapter.

7.2 Reporting Requirements.

7.2.1 General Reporting Provisions. The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 Notifications. The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with §63.10030.

7.2.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in §63.9984. Also submit the monitoring plan information in §75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.
7.2.4 Certification, Recertification, and Quality-Assurance Test Reporting. Except for daily QA tests of the required monitoring systems (i.e., calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 Quarterly Reports.

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 Compliance Certification. Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.


Appendix B to Subpart UUUUU of Part 63—HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 Monitoring System Installation Requirements. Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with §63.1010(a) and either Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS.
2.2 **Primary and Backup Monitoring Systems.** The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 **FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.** The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter; or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 If you choose to follow PS 15 of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) “Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy” (incorporated by reference, see §63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤R ≤130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

\[
\text{Reported Result} = \frac{\text{Measured Concentration in Stack}}{\%R} \times 100
\]  
(Eq. B-1)
3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 If you choose to follow PS 18 of appendix B to part 60 of this chapter, then your HCl CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.4.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ±5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, “quarterly” means once every “QA operating quarter” (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for “non-QA operating quarters” (i.e., calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.4.2.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, “annual” means once every four “QA operating quarters” (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures in Procedure 6 of appendix F to part 60 of this chapter shall apply. The quarterly
and annual QA tests required under Procedure 6 shall be performed, respectively, at the frequencies specified in sections 5.1.2 and 5.1.3 of this appendix.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3.1 Out-of-Control Periods. A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 Grace Periods. For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 Conditional Data Validation. For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (i.e., 168 unit or stack operating hours).

5.4 Data Validation.

5.4.1 Out-of-Control Periods. An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was
either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 Grace Periods. For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit or other quarterly data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 Conditional Data Validation. For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in §75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (i.e., 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that
the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 General Requirements for HCl and HF CEMS.

8.1.1 Preventive Maintenance. Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 Recordkeeping and Reporting. Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 Maintenance Records. Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 Specific Requirements for HCl and HF CEMS. The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with §60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in Appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by $9.43 \times 10^{-8}$ to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is $5.18 \times 10^{-8}$. The appropriate diluent cap value from section 6.2.1.2 of Appendix A to this subpart may be used to calculate the HCl or HF emission rate (lb/MMBtu) during startup or shutdown hours.

9.3.2 For gross output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with $9.43 \times 10^{-8}$ lb/scf-ppm (for HCl) or $5.18 \times 10^{-8}$ (for HF) and defining $C_h$ as the hourly average HCl or HF concentration in ppm. Then, divide the result by the hourly gross output (megawatts) to convert it to units of lb/MWh. If the gross output is zero during a startup or shutdown hour, use the default gross output (as defined in §63.10042) to calculate the HCl or HF emission rate. The default gross output is not considered to be a substitute data value.
9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term $E_{10}$ in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 Monitoring Plan Records. For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (i.e., flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 Updates. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 Contents of the Monitoring Plan. For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under §75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 Electronic. Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (i.e., CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 Hard Copy. Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 Operating Parameter Records. For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator); and

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.2.5 If applicable, a flag to indicate that the hour is a startup or shutdown hour (as defined in §63.10042).
10.1.3  **HCl and/or HF Emissions Records.** For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1  The date and hour;

10.1.3.2  Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3  The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4  A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5  Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

10.1.4  **Stack Gas Volumetric Flow Rate Records.**

10.1.4.1  Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (i.e., lb/MWh or lb/GWh).

10.1.4.2  Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

10.1.5  **Records of Stack Gas Moisture Content.**

10.1.5.1  Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1  To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2  To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2  If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from §75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

10.1.6  **Records of Diluent Gas (CO₂ or O₂) Concentration.**

10.1.6.1  To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO₂ or O₂ concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2  If hourly measurements of diluent gas concentration are needed, you must use a certified CO₂ or O₂ monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO₂ or O₂ concentration records, as specified in §75.57(g) of this chapter.

10.1.7  **HCl and HF Emission Rate Records.** For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1  The date and hour;
10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.7.5 If applicable, a code to indicate that the default electrical load (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.7.6 If applicable, a code to indicate that the diluent cap (as defined in §63.10042) was used to calculate the HCl or HF emission rate.

10.1.8 Certification and Quality Assurance Test Records. For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 HCl and HF CEMS.

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 Additional Monitoring Systems. For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and ongoing quality-assurance tests of these systems, as specified in §75.59(a) of this chapter.

11. Reporting Requirements

11.1 General Reporting Provisions. The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 Notifications. The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with §63.10030.
11.3 Monitoring Plan Reporting. For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in §63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 Certification, Recertification, and Quality-Assurance Test Reporting Requirements. Except for daily QA tests (i.e., calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in §75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:
11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 \textit{Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.} For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 \textit{Quarterly Reports.}

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;
11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 Compliance Certification. Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Source Description and Location

Source Name: Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station
Source Location: 8511 Welborn Road, Mount Vernon, IN 47620
County: Posey
SIC Code: 4911 and 4922 (Electric Services and Natural Gas Transmission)
Permit Renewal No.: T 129-40544-00010
Permit Reviewer: Bharathi Bhattu/Tamara Havics

On October 4, 2018, Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station submitted an application to the Office of Air Quality (OAQ) requesting to renew its operating permit. OAQ has reviewed the operating permit renewal application from Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station relating to the operation of a stationary electric utility generating station. Southern Indiana Gas and Electric Company (SIGECO) - A.B. Brown Generating Station was issued its second Part 70 Operating Permit Renewal (T129-33047-00010) on November 07, 2014.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. T 129-33047-00010 on November 07, 2014. The source has since received the following approvals:

(a) Significant Permit Modification No.: 129-38980-00010, issued on November 28, 2017.
(b) Significant Source Modification No.: 129-38765-00010, issued on November 8, 2017.
(c) Significant Permit Modification No.: 129-35974-00010, issued on December 28, 2015.
(d) Significant Permit Modification No.: 129-37317-00010, issued on January 30, 2017.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Emission Units and Pollution Control Equipment

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart D, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]
(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low-NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

[Under 40 CFR 60, Subpart Da, this is an affected facility]
[Under 40 CFR 63, Subpart UUUUU, this is an affected facility]

(c) One (1) simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(d) One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOx) and carbon monoxide (CO), exhausting to stack No.4.

[Under 40 CFR 60, Subpart GG, this is an affected facility]

(e) A coal storage and handling system, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, with a maximum throughput of 600 tons of coal per hour, consisting of the following equipment:

1. One (1) railcar and truck unloading station with particulate emissions controlled by enclosure, with a drop point to the coal pile.

2. One (1) storage pile, having a storage capacity of 700,000 tons, with fugitive emissions controlled by a watering system.

3. An enclosed conveyor system, with a maximum feed rate of 600 tons per hour, with the transfer points underground or enclosed by buildings, and exhausting inside the transfer buildings or powerhouse.

4. Twelve (12) enclosed coal pulverizers, each with a maximum capacity of twenty (20) tons of coal per hour, and exhausting to the boilers

(f) A lime storage and handling system with maximum loading of 42000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

1. One (1) railcar and truck unloading station, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.

2. Two (2) storage silos, each with a maximum capacity of 1300 tons, each with a fabric filter to recover the pneumatically conveyed material.

3. One (1) storage silo, with a storage capacity of 2600 tons, each with a fabric filter to recover the pneumatically conveyed material.
(4) Three (3) usage bins, each with a storage capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(g) A soda ash storage and handling system with maximum loading of 6000 pounds per hour, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, consisting of the following equipment:

1. One (1) railcar and truck unloading station, with particulate matter emissions controlled by enclosure, with pneumatic conveyance to the storage silos, with a maximum flow rate of 1500 cfm.

2. Two (2) storage silos, each with a maximum capacity of 200 tons, each with a fabric filter to recover the pneumatically conveyed material.

(h) The wet fly and bottom ash handling system was installed and expanded with start-up dates of 1979 (installed with Boiler Unit No. 1) and 1985 (installed with Boiler Unit No. 2). The dry fly ash (DFA) system was subsequently added to accommodate the option for product recovery of DFA material through a separate storage, handling, and barging operation to an off-site location. The DFA handling system interfaces with the existing wet ash system at the Hydroveyor. (Hydroveyor No. 1 for A. B. Brown No. 1 and Hydroveyor No. 2 for A. B. Brown No. 2). Each existing Hydroveyor is a water-exhauster powered-vacuum system that conveys ash in a dry state up to the exhauster where it then converts to slurry form and then flows to an ash separator where the conveying air is vented off and the slurry flows by gravity to the existing ash pond. The existing handling system was modified to incorporate the all-dry filter/separar design (Filter/Separator No. 1 for A. B. Brown No. 1 and Filter/Separator No. 2 for A. B. Brown No. 2). Each Hydroveyor remains in-service and each filter/separator, with bypasses, intercept the fly ash for transport to the storage silo. Each existing Hydroveyor continues to discharge water to the existing ash pond and the existing fly ash system continues to route fly ash slurry flows to the ash pond for maintenance or product quality episodes. The filter/separators discharge to the Intermediate Silo (storage capacity of 2500 tons). The Intermediate Silo is equipped with a bin vent filter and truck unloading station. The truck unloading station receives ash from other Vectren operations for transfer to the Barge Loader. The truck unloading station is equipped with two truck bays to receive ash product. The transport and handling system that extends from the Intermediate Silo and through to the Barge Loader is a common (single) system with a design capacity of 700 ton/hr. The Intermediate Silo discharge is fitted with a feeder to load the dry conveyor (belt) for transport to the Barge Loading Transfer Tower. The Barge Loading Transfer Tower conveys DFA, via air-slide, to the barge. The DFA product enters the barge through a telescopic loading nozzle fitted with a dust control ring to control fugitive dust. The Barge Loader conveyor is equipped with a fabric filter dust collector which vents to the atmosphere.

(i) Scrubber sludge handling, with initial construction after 1974 and before initial startup of Unit 1 boiler in 1979, modified in 1984 and 1985 for Unit No. 2 boiler, with wet sludge conveyed to haul trucks.

### Insignificant Activities

The source also consists of the following insignificant activities:

(a) Combustion source flame safety purging on startup.

(b) A gasoline fuel transfer and dispensing operation handling less than or equal to 1,300 gallons per day, such as filling of tanks, locomotives, automobiles, having a storage capacity less than or equal to 10,500 gallons.

(c) A petroleum fuel, other than gasoline, dispensing facility having a storage capacity less than or equal to 10,500 gallons, and dispensing less than or equal to 230,000 gallons per month.
(d) The following VOC and HAP storage containers:

(1) Storage tanks with capacity less than or equal to 1,000 gallons and annual throughput less than 12,000 gallons.

(2) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids.

(e) Machining where an aqueous cutting coolant continuously floods the machining interface.

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

(g) The following equipment performing maintenance activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(h) Solvent recycling systems with batch capacity less than or equal to 100 gallons.

(i) Activities associated with the transportation and treatment of sanitary sewage, provided discharge to the treatment plant is under the control of the owner/operator, that is, an on-site sewage treatment facility.

(j) Noncontact cooling tower systems with either of the following: Forced and induced draft cooling tower system not regulated under a NESHAP.

(k) Replacement or repair of electrostatic precipitators, bags in baghouses and filters in other air filtration equipment.

(l) Heat exchanger cleaning and repair.

(m) Stockpiled soils from soil remediation activities that are covered and waiting transportation for disposal.

(n) Paved and unpaved roads and parking lots with public access.

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

(p) Asbestos abatement projects.

(q) Purging of gas lines and vessels that is related to routing maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(r) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment.

(s) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(t) On-site fire and emergency response training approved by the department.

(u) Two (2) distillate oil-fired emergency generators rated 398 bhp each, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, these are affected facilities.]

(v) One (1) distillate oil-fired fire pump rated 200 bhp, installed in 1974.

[Under 40 CFR 63 Subpart ZZZZ, this is an affected facility]
(w) Vents from ash transport systems not operated at positive pressure.

(x) A laboratory as defined in 326 IAC 2-7(21)(D).

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

(1) Fuel Oil Storage Tank #1
(2) Fuel Oil Storage Tank #2
(3) Boiler Chemical cleaning waste evaporation
(4) Ash pond and ash pond maintenance, with water cover, vegetation, wind barriers, commercial dust control product, or other means sufficient to prevent ash re-entrainment.

### Emission Units and Pollution Control Equipment Removed From the Source

The source has removed the following insignificant emission unit:

(a) Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour:

(1) One (1) natural gas-fired auxiliary boiler, identified as Unit No. 8, constructed in 1977, with a heat input capacity of 0.0335 MMBtu per hour and exhausting to stack #5.

### Enforcement Issue

There are no enforcement actions pending.

### Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

### County Attainment Status

The source is located in Posey County.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>Better than national standards.</td>
</tr>
<tr>
<td>CO</td>
<td>Unclassifiable or attainment effective November 15, 1990.</td>
</tr>
<tr>
<td>O3</td>
<td>Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.¹</td>
</tr>
<tr>
<td>PM2.5</td>
<td>Unclassifiable or attainment effective April 15, 2015, for the 2012 annual PM2.5 standard.</td>
</tr>
<tr>
<td>PM10</td>
<td>Unclassifiable effective November 15, 1990.</td>
</tr>
<tr>
<td>NO2</td>
<td>Unclassifiable or attainment effective January 29, 2012, for the 2010 NO2 standard.</td>
</tr>
<tr>
<td>Pb</td>
<td>Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.</td>
</tr>
</tbody>
</table>

¹Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.
(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) PM$_{2.5}$
Posey 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
Posey County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

---

### Fugitive Emissions

Since this source is classified as an electric utility generating station, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

---

### Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of [Utility Air Regulatory Group v. EPA](http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf), cause no. 12-1146, the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources “previously classified as ‘Major’ based solely on greenhouse gas emissions.”

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.
## Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

<table>
<thead>
<tr>
<th>Unrestricted Potential Emissions (ton/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM&lt;sup&gt;1&lt;/sup&gt;</td>
</tr>
<tr>
<td>---------------</td>
</tr>
<tr>
<td>Total PTE of Entire Source Including Fugitives*</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
</tr>
</tbody>
</table>

1Under the Part 70 Permit program (40 CFR 70), PM<sub>10</sub> and PM<sub>2.5</sub>, not particulate matter (PM), are each considered as a "regulated air pollutant."
2PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.
3Single highest source-wide HAP
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10, PM2.5, SO<sub>2</sub>, NO<sub>x</sub>, VOC, and CO is equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) This existing source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs.

## Actual Emissions

The following table shows the actual emissions as reported by the source. This information reflects the 2017 OAQ emission data.

<table>
<thead>
<tr>
<th>Actual Emissions (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM&lt;sub&gt;10&lt;/sub&gt;</td>
</tr>
<tr>
<td>120</td>
</tr>
</tbody>
</table>

*Lead and lead compounds, including any unique chemical substance that contains lead.

## Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

## Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal,
and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

<p>| Potential To Emit of the Entire Source After Issuance of Renewal (tons/year) |
|-----------------|---|---|---|---|---|---|---|---|</p>
<table>
<thead>
<tr>
<th>PM³</th>
<th>PM₁₀³</th>
<th>PM₂₅₁,₂</th>
<th>SO₂</th>
<th>NOₓ</th>
<th>VOC</th>
<th>CO</th>
<th>H₂SO₄</th>
<th>Single HAP³</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total PTE of Entire Source Including Fugitives*</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;10</td>
<td>&gt;25</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
<td>NA</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>NA</td>
<td>10</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

*Under the Part 70 Permit program (40 CFR 70), PM₁₀ and PM₂₅, not particulate matter (PM), are each considered as a "regulated air pollutant."
²PM₂₅ listed is direct PM₂₅.
³Single highest source-wide HAP.
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (Prevention of Significant Deterioration) for information regarding the PSD BACT limit(s) and PSD minor limit(s).

(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) This source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

**Federal Rule Applicability**

Federal rule applicability for this source has been reviewed as follows:

**New Source Performance Standards (NSPS):**

(a) **40 CFR 60, Subpart D-Standard of Performance for Fossil - Fuel Steam Generators for Which Construction is Commenced After August 17, 1971.**

The pulverized coal-fired boiler, identified as Boiler Unit 1, is subject to the requirements of 40 CFR 60, Subpart D and 326 IAC 12, because the pulverized coal-fired boiler was constructed in 1974, which is after the applicability date (August 17, 1971) for this rule and the boiler has a heat input capacity of greater 250 million Btu/hour.

The units subject to this rule include the following:

(1) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV), with a fabric filter for control of particulate matter (PM), with a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO₂), with low-nitrogen oxides (NOx) combustion (low-excess air and low NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent
injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg) and exhausting to stack #1. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

This emission unit is subject to the following portions of Subpart D:

1. 40 CFR 60.40(a)(1)
2. 40 CFR 60.41
3. 40 CFR 60.42(c)
4. 40 CFR 60.43
5. 40 CFR 60.44
6. 40 CFR 60.45 and
7. 40 CFR 60.46

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the unit except as otherwise specified in 40 CFR 60, Subpart D.

(b) 40 CFR 60, Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

The pulverized coal-fired boiler, identified as Boiler Unit No. 2 is subject to the requirements of 40 CFR 60, Subpart Da and 326 IAC 12, because the boiler was constructed in 1979, which is after the applicability date (September 18, 1978) for this rule, and the boiler has a heat input capacity of greater 250 million Btu/hour.

The units subject to this rule include the following:

1. One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV), with an electrostatic precipitator (ESP) system for control of particulate matter (PM) and a dual alkali flue gas desulfurization (FGD) system for control of sulfur dioxide (SO2), with low-nitrogen oxides (NOx) combustion (low-excess air and low -NOx burners) and selective catalytic reduction (SCR) system for control of NOx, with sorbent injection system for control of sulfur trioxide (SO3) and resulting sulfuric acid (H2SO4) emissions, with continuous emissions monitoring systems (CEMS) for PM, NOx, SO2, and mercury (Hg), and exhausting to stack No. 2. Natural gas (NG) can be used for startup, shutdown, and malfunctions.

This emission unit is subject to the following portions of Subpart Da:

1. 40 CFR 60.40Da (a)(1) and (a)(2)
2. 40 CFR 60.41Da
3. 40 CFR 60.42Da (a) and (b)(1)
4. 40 CFR 60.43Da (a)(1) through (a)(4), and (g)
5. 40 CFR 60.44Da (a)(1)
6. 40 CFR 60.48Da (a), (b), (d), (e), (f), (h), (q), & (s)
7. 40 CFR 60.49Da (a)(1), (b)(1), (b)(4), (c), (d), (e), (f)(1), (g), (h), (i), (j), (s), (t), (v), & (w)
8. 40 CFR 60.50Da (a), (b)(1), (b)(3), (c), (d), & (e)
9. 40 CFR 60.51Da (a), (b), (c), (f), (h), (i), (j), & (k)
10. 40 CFR 60.52Da

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the unit except as otherwise specified in 40 CFR 60, Subpart Da.

(c) 40 CFR 60, Subpart GG-Standard of Performance for Stationary Gas Turbines.

The two (2) combustion turbines, identified as Unit ABB No. 3 and Unit ABB No. 4, are subject to the requirements of the 40 CFR 60, Subpart GG and 326 IAC 12, because the turbines were
constructed in 1991 and 2002, respectively, which is after the applicability date (October 3, 1977) for this rule, and the turbines have a heat input capacity of greater than 10 million Btu/hour, each.

The units subject to this rule include the following:

1. One (1) simple-cycle, natural gas-fired combustion turbine, designated as unit ABB No. 3, constructed in 1991, with a design fuel heat input capacity of 897.4 million Btu per hour (nominal LHV), utilizing distillate oil (No. 2 fuel oil) as a backup fuel, with a water injection system for control of NOx emissions, with a parametric emissions monitoring (PEMS) system for NOx and exhausting to stack #3.

2. One (1) simple cycle natural gas-fired combustion turbine, identified as unit ABB No. 4, constructed in 2002, with a design fuel heat input capacity of 1146 million (MM) Btu per hour (maximum HHV), with dry low-NOx combustion, with continuous emissions monitoring (CEMS) system for nitrogen oxides (NOX) and carbon monoxide (CO), exhausting to stack No.4.

These emission units are subject to the following portions of Subpart GG:

1. 40 CFR 60.330(a) and (b)
2. 40 CFR 60.331
3. 40 CFR 60.332(a)(1), (a)(3), (a)(4), (b), (f), and (k)
4. 40 CFR 60.333
5. 40 CFR 60.334(a), (b), (g), (h), (i)(2), (i)(3), (j)(1)(i), (j)(1)(ii), (j)(2)(i), (j)(2)(ii), (j)(3), (j)(4), and (j)(5)
6. 40 CFR 60.335(a), (b), and (c)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the units except as otherwise specified in 40 CFR 60, Subpart GG.

(d) The requirements of the New Source Performance Standard for Coal Preparation Plants, 40 CFR 60, Subpart Y and 326 IAC 12, are not included in the permit for the coal storage and handling operations, because the operations don’t meet the definition of a coal preparation plant. Only conveying and storage is performed onsite. All coal is crushed before delivery.

(e) The requirements of the New Source Performance Standard for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the lime handling operations, because the source does not do any crushing of lime, only storage and conveying.

(f) The requirements of the New Source Performance Standard for Stationary Spark Ignition Internal Combustion Engines, 40 CFR 60, Subpart JJJJ and 326 IAC 12, are not included in the permit for the two (2) diesel-fired emergency generators and one (1) diesel-fired fire pump, because the units are compression ignition generators.

(g) The requirements of the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart III and 326 IAC 12, are not included in the permit for the two (2) diesel-fired emergency generators and one (1) diesel-fired fire pump, because the emergency generators were manufactured prior April 1, 2006, and the fire pump was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine prior to July 1, 2006.

(h) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit.
National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) 40 CFR 63, Subpart YYYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
The requirements of the 40 CFR 63, Subpart YYYYY, which is incorporated by reference as 326 IAC 20-90, apply to stationary combustion turbines located at major sources of HAP emissions. However, 40 CFR 63.6090(b)(4) states that existing stationary combustion turbine (construction or reconstruction commencing on or before January 14, 2003) "do not have to meet the requirements of this subpart and of subpart A of this part." Therefore, the requirements of 40 CFR 63, Subpart YYYYY do not apply to the two (2) simple-cycle, natural gas-fired combustion turbines, identified as units ABB No. 3 and ABB No. 4.

(b) 40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines
The two (2) diesel-fired emergency generators, and one (1) diesel-fired fire pump, each constructed in 1974, are subject to the requirements of the 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because these facilities are considered existing stationary reciprocating internal combustion engines (RICE), compression ignition (CI), constructed prior to June 12, 2006 at a major source of hazardous air pollutants (HAP).

The units subject to this rule include the following:

1. Two (2) distillate oil-fired emergency generators rated 398 bhp each, installed in 1974.
2. One (1) distillate oil-fired fire pump rated 200 bhp, installed in 1974.

These emission units are subject to the following portions of Subpart ZZZZ:

1. 40 CFR 63.6580
2. 40 CFR 63.6585(a) and (b)
3. 40 CFR 63.6590(a)(1)(ii) and (a)(1)(iv)
4. 40 CFR 63.6595 (a)(4) and (c)
5. 40 CFR 63.6602
6. 40 CFR 63.6604(b)
7. 40 CFR 63.6605
8. 40 CFR 63.6612 (a) and (b) (Testing)
9. 40 CFR 63.6620(a)
10. 40 CFR 63.6625(e)(2), (f), (h), and (i)
11. 40 CFR 63.6630(a), (b), and (c)
12. 40 CFR 63.6635
13. 40 CFR 63.6640 (a), (f)(1), (f)(2)(i), (f)(3)
14. 40 CFR 63.6645(a)(5)
15. 40 CFR 63.6650(f)
16. 40 CFR 63.6655(e)(2) and (f)(1)
17. 40 CFR 63.6660
18. 40 CFR 63.6665
19. 40 CFR 63.6670
20. 40 CFR 63.6675
21. Item 1 of Table 2c
22. Item 1 of Table 4
23. Item 9 and 10 of Table 6
24. Table 8

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart ZZZZ.
On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA’s Guidance Memo: https://www3.epa.gov/airtoxics/icengines/docs/RICEVacaturGuidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as strikethrough text. At this time, IDEM is not making any changes to the permit’s attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(c) 40 CFR 63, Subpart UUUUU - National Emission Standard for Hazardous Air Pollutants for Coal and Oil Fired Electric Utility Steam Generating Units

The two (2) dry bottom, pulverized coal-fired boilers, identified as No.1 and No.2 are subject to the requirements of the 40 CFR 63, subpart UUUUU, which is incorporated by reference as 326 IAC 20-89, because they are existing electric steam generating unit that emitted hazardous air pollutants (HAP) from coal fired electric utility steam generating units (EGUs) as defined in §63.10042 and must comply with this subpart no later than April 16, 2015.

The units subject to this rule include the following:

(1) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 1, constructed in 1974, with a startup date of 1979, with a design fuel heat input capacity of 2518 million (MM) Btu per hour (nominal HHV)

(2) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler Unit No. 2, constructed in 1979 with a startup date of 1985, with a design fuel heat input capacity of 2530 million (MM) Btu per hour (nominal HHV)
These emission units are subject to the following portions of Subpart UUUUU:

(1) 40 CFR 63.9980
(2) 40 CFR 63.9981
(3) 40 CFR 63.9982 (a)(1)
(4) 40 CFR 63.9984 (b)
(5) 40 CFR 63.9990 (a)(1)
(6) 40 CFR 63.9991
(7) 40 CFR 63.10000 (a), (b),(c)(1), (d),& (e)
(8) 40 CFR 63.10005(a)(2), (d), (e), (j), and (k)
(9) 40 CFR 63.10006(a), (c), (f), (g), and (i)
(10) 40 CFR 63.10007(a)(1), (b), (d), (e)(1), (e)(3), (f), and (g)
(11) 40 CFR 63.10009(a), (b), (c), (d), (e), (f)(1), (h), and (j)(1)
(12) 40 CFR 63.10010(a)(1), (e), (f), (g), (j), and (l)
(13) 40 CFR 63.10011(a), (c), (e), (f), (g)
(14) 40 CFR 63.10020(a), (b), (c), (d), (e)(1), and (e)(2)
(15) 40 CFR 63.10021(a), (b), (e), (f), (g), (h), and (i)
(16) 40 CFR 63.10022(a)(1), (a)(4), and (b)
(17) 40 CFR 63.10030(a), (b), (d), and (e)
(18) 40 CFR 63.10031(a), (b), (c), (d), (e), (f), and (g)
(19) 40 CFR 63.10032(a), (b), (f), and (h)
(20) 40 CFR 63.10033
(21) 40 CFR 63.10040
(22) 40 CFR 63.10041
(23) 40 CFR 63.10042
(24) Item 1 of Table 1 to Subpart UUUUU of Part 63
(25) Item 1 of Table 2 to Subpart UUUUU of Part 63
(26) Items 1, 3, and 4 of Table 3 to Subpart UUUUU of Part 63
(27) Items 1, 3, 4, and 5 of Table 5 to Subpart UUUUU of Part 63
(28) Items 1, 4, 5, 6, and 7 of Table 7 to Subpart UUUUU of Part 63
(29) Item 1 of Table 8 to Subpart UUUUU of Part 63
(30) Table 9 to Subpart UUUUU of Part 63
(31) Appendix A to Subpart UUUUU of Part 63
(32) Appendix B to Subpart UUUUU of Part 63

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63 Subpart UUUUU.

(d) The requirements of National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers, 40 CFR 63, Subpart Q, applies to cooling towers operating with chromium-based water treatment chemicals that are either major sources of HAP or are integral parts of a facility that is a major source of HAP. The cooling tower water treatment chemicals are not chromium based, so the requirements of Subpart Q are not applicable to the cooling towers.

(e) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included in the permit.

**Compliance Assurance Monitoring (CAM):**

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and
(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO2 and NOX under the Acid Rain Program.

(d) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

<table>
<thead>
<tr>
<th>Emission Unit/Pollutant</th>
<th>Pollutant</th>
<th>Control Device</th>
<th>Applicable Emission Limitation</th>
<th>Uncontrolled PTE (tons/year)</th>
<th>Controlled PTE (tons/year)</th>
<th>CAM Applicable (Y/N)</th>
<th>Large Unit (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler, Unit No. 1</td>
<td>PM</td>
<td>BH</td>
<td>326 IAC 2-2</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>N¹</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>PM10</td>
<td>None</td>
<td>None</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>N²</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>PM2.5</td>
<td>None</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td></td>
<td>N²</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>H₂SO₄</td>
<td>sorbent injection system</td>
<td>1692 CD No. IP99-1692 C-M/F</td>
<td>&gt;100</td>
<td>&lt;100</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Boiler, Unit No. 2</td>
<td>PM</td>
<td>ESP</td>
<td>326 IAC 2-2</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>N¹</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>PM10</td>
<td>None</td>
<td>None</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>N²</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>PM2.5</td>
<td>None</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td></td>
<td>N²</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>H₂SO₄</td>
<td>sorbent injection system</td>
<td>1692 CD No. IP99-1692 C-M/F</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>Y</td>
<td>Y</td>
</tr>
</tbody>
</table>

Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for criteria pollutants (PM10, PM2.5, SO2, NOX, VOC and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy.

Under the Part 70 Permit program (40 CFR 70), PM is not a regulated pollutant.

PM* For limitations under 326 IAC 6-3-2, 326 IAC 6.5, and 326 IAC 6.8, IDEM OAQ uses PM as a surrogate for the regulated air pollutant PM10. Therefore, uncontrolled PTE and controlled PTE reflect the emissions of the regulated air pollutant PM10.

N¹ Under 326 IAC 2-2, PM is not a surrogate for a regulated air pollutant. Therefore, CAM does not apply to these emission units for the 326 IAC 2-2 PM limitation.

N² The control device is not required to comply with the applicable emission limitation or standard. Therefore, based on this evaluation, the requirements of 40 CFR Part 64, CAM, are not applicable.

Controls: BH = Baghouse, ESP = Electrostatic Precipitator

Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are applicable to coal-fired boiler Unit No. 1, and coal-fired boiler Unit No. 2, which is considered a "large unit," for H₂SO₄. A CAM plan was submitted as part of a previous permit application and the Compliance Determination and Monitoring Requirements section includes a detailed description of the CAM requirements.

**Clean Air Interstate Rule (CAIR):**
The Clean Air Interstate Rule (CAIR) have been repealed, therefore, CAIR requirements have been removed from the permit.

**Cross State Air Pollutant Rule (CSAPR)**

The preamble of the CSAPR regulations promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR Part 70 and 71. The requirements of the Cross-State Air Pollution Rule (CSAPR) apply to the existing two (2) boilers (Unit No. 1 and Unit No. 2) and the two (2) simple cycle combustion turbines (ABB No.3 and ABB No.4).

**Description of TR Monitoring Provisions**

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season Trading Program and TR SO2 Group 1 Trading Program.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO2 monitoring) and 40 CFR part 75, subpart H (for NOx monitoring)</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
<th>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</th>
<th>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix E</th>
<th>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>X</td>
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<tr>
<td>Heat input</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO2 monitoring) and 40 CFR part 75, subpart H (for NOx monitoring)</th>
<th>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</th>
<th>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</th>
<th>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix E</th>
<th>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat input</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Parameter</td>
<td>Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO₂ monitoring) and 40 CFR part 75, subpart H (for NOₓ monitoring)</td>
<td>Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D</td>
<td>Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E</td>
<td>Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix E</td>
<td>EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E</td>
</tr>
<tr>
<td>-------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------</td>
<td>-----------------------------------------------------------------</td>
<td>-----------------------------------------------------------------</td>
<td>----------------------------------------------------------------</td>
<td>----------------------------------------------------------------</td>
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<tr>
<td>SO₂</td>
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<tr>
<td>NOₓ</td>
<td>X</td>
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<td></td>
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</tr>
<tr>
<td>Heat input</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Unit ID: ABB No. 3
ORIS ID: 6137

Unit ID: ABB No. 4
ORIS ID: 6137
1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA’s website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative monitoring system is available on the EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator’s response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA’s website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

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**State Rule Applicability - Entire Source**

State rule applicability for this source has been reviewed as follows:

**326 IAC 1-6-3 (Preventive Maintenance Plan)**
The source is subject to 326 IAC 1-6-3.

**326 IAC 1-5-2 (Emergency Reduction Plans)**
The source is subject to 326 IAC 1-5-2.

**326 IAC 2-2 (Prevention of Significant Deterioration)**
PSD and Emission Offset applicability is discussed under the Potential to Emit After Issuance section of this document.

**PSD BACT Limits**

(1) Pursuant to PSD (65) 1355 issued on February 22, 1979, the emission rates from boiler Unit No.2 shall not exceed the following:

   (a) Particulate matter (PM) - 0.03 pounds per million Btu (MMBtu) of energy input.

   (b) Sulfur dioxide - 0.69 pounds per million Btu (MMBtu) of energy input.
(c) Nitrogen oxides - 0.6 pounds per million Btu (MMBtu) of energy input.

(d) The stack gas particulate emissions shall be controlled by an electrostatic precipitator having a minimum collection efficiency of 99.6% when burning coal with a maximum ash content of 10%, a minimum sulfur content of 2.5% and a minimum heat content of 11,000 Btu's per pound.

(e) Sulfur dioxide shall be controlled by a scrubber having a minimum control efficiency of 90.0%.

(2) Pursuant to 326 IAC 2-2-3 (PSD BACT) and Significant Source Mod 129-14021-00001, issued November 16, 2001, emissions from ABB No. 4 shall comply with the following:

**PM10**

(a) Gas turbine emissions shall be less than 0.0050 pounds per MMBtu on a higher heating value basis, which is equivalent to five (5) pounds per hour.

(b) Perform good combustion.

**NOx**

(c) Use dry low-NOx combustors in conjunction with natural gas.

(d) During normal simple cycle operation (i.e., steady-state operating condition), the NOx emissions from combustion turbine when burning natural gas shall be less than 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 36 pounds per hour.

(e) The annual NOx emissions from ABB No. 4 burning natural gas shall be less than 132.06 tons per twelve (12) consecutive month period, excluding startup and shutdown emissions, with compliance determined at the end of each month.

**CO**

(f) During normal simple cycle operation (i.e., steady-state operating condition), the CO emissions from combustion turbine, when burning natural gas, shall be less than 25 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 60 pounds per hour.

(g) Good combustion practices shall be applied to minimize CO emissions.

**Startup/Shutdown**

(h) Startup is defined as the period of time between the initiation of combustion firing from a "cold start" operating condition and the attainment of steady-state operating condition.

(i) Shutdown is defined as that period of time between the initial lowering of the turbine output and the complete cessation of fuel combustion in the unit with the intent to shut down to a "cold stop" condition.

(j) The ABB No. 4 shall comply with the following:

(A) The maximum number of events (where one event is one startup and one shutdown) shall be less than 240 per twelve (12) consecutive month period rolled on monthly basis as determined at the end of each calendar month. The duration of an event shall not exceed one (1) hour.

(B) The NOx emissions from ABB No. 4 stack shall be less than 36 pounds per event. ABB No. 4 shall emit less than 3.8 tons of NOx during startup and shutdown per twelve (12) consecutive month period, with compliance determined at the end of each month.
The CO emissions from ABB No. 4 stack shall be less than 65 pounds per event. ABB No. 4 shall emit less than 14.93 tons of CO during startup and shutdown per twelve (12) consecutive month period, with compliance determined at the end of each month.

**PSD Minor Limits**

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

(a) The nitrogen oxides (NOx) emissions from ABB No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, and the sulfur dioxide (SO2) emissions from ABB No. 3 shall be limited to less than 40 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The amount of distillate oil (No. 2 fuel oil) combusted in ABB No. 3 shall be less than 1,893,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) The sulfur content of any fuel used in the turbine (natural gas or oil) shall not exceed 0.3 percent (%) by weight.

Compliance with these limits shall limit the potential to emit from Construction Permit PC (65) 1802, issued on November 6, 1989, of NOx and SO2 to less than forty (40) tons per twelve (12) consecutive month period, each, and shall render the requirements of 326 IAC 2-2 (PSD) not applicable.

**326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))**

The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of the two (2) dry bottom, pulverized coal-fired boilers, identified as Unit No. 1 and Unit No. 2, constructed in 1974 and 1979, are exempt from the requirements of 326 IAC 2-4.1, because they were constructed before July 27, 1997.

The operation of the simple-cycle, natural gas-fired combustion turbine, identified as unit ABB No. 3, constructed in 1991, is exempt from the requirements of 326 IAC 2-4.1, because it was constructed before July 27, 1997.

**HAP Limits:**

Pursuant to Significant Source Mod 129-14021-00001, issued November 16, 2001, and in order to render the requirements of 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP)) not applicable, the Permittee shall comply with the following:

(a) The emission of single HAP, formaldehyde, from the ABB No. 4 combustion turbine shall be limited to less than 0.00071 lb/MMBtu.

(b) The amount of MMBtu fired in the turbine shall be less than 10,038,960 MMBtu per twelve (12) consecutive month period with compliance determination at the end of each month.

Compliance with these limits shall limit the formaldehyde emissions from ABB No. 4 to less than ten (10) tons per twelve (12) consecutive month period, and shall render the requirements of 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP)) not applicable.
326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting), because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of PM10, and PM2.5 is greater than 250 tons per year, and the potential to emit of CO, NOx, SO2 is greater than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 2-7-6(5) (Annual Compliance Certification)
The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

326 IAC 6-4 (Fugitive Dust Emissions)
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 6-5 (Fugitive Particulate Matter Emission Limitations)
This source was constructed before December 13, 1985, but has received construction approvals after this date. The source has potential fugitive particulate emissions of twenty-five (25) tons per year or more. Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the Fugitive Dust Control Plan that is included as Attachment A to the permit.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Posey County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Posey County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in Posey County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs))
The source is subject to 326 IAC 24, because the requirements of 40 CFR Part 97 (Cross-State Air Pollution Rule (CSAPR)) apply to the coal-fired boilers Unit No.1 and Unit No. 2, and simple cycle combustion turbines ABB No. 3 and ABB No. 4.

State rule applicability has been reviewed as follows:

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

(b) If this facility cannot meet the opacity limitation of 326 IAC 5-1-3(a), the Permittee may submit a
written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with
326 IAC 5-1-3(e). The Permittee must demonstrate that the alternative limit is needed and
justifiable.

326 IAC 6-2-3 (Particulate Emissions Limitations for Indirect Heating Facilities)
The dry bottom, pulverized coal-fired boilers Unit No. 1 and No. 2 are subject to 326 IAC 6-2-3
(Particulate Emissions for Sources of indirect Heating), because they were existing and in operation or
received permits to construct prior to September 21, 1983. Pursuant to this rule, the particulate matter
emissions from the coal-fired boiler Unit No.1 and No. 2 shall not exceed 0.433 lb/MMBtu, each.

\[
Pt = \frac{a \cdot h \cdot C}{76.5 \cdot Q^{0.75} \cdot N^{0.25}} = 0.433 \text{ lb/MMBtu}
\]

Where:

- \(C\) = 50 micrograms/cu. Meter, maximum ground level concentration
- \(Q\) = 5058 MMBtu/hr, heat input rate (2518 + 2530 = 5048 MMBtu/hr)
- \(N\) = 1 number of stacks
- \(a\) = 0.8 dimensionless, plume rise factor
- \(h\) = 496 ft, average stack height

Pursuant to 40 CFR 60.40, Subpart D, the particulate matter (PM) emission limit for coal-fired boiler Unit
No. 1 is 0.1 lbs/MMBtu. Since the PM limit for the coal-fired boiler Unit No.1 from 40 CFR 60, Subpart D
is more stringent than the PM limit from 326 IAC 6-2-3, pursuant to 326 IAC 6-3-1(c)(5), the coal-fired
boiler Unit No.1 is exempt from the requirements of 326 IAC 6-2-3.

Pursuant to 40 CFR 60.40 Subpart Da, the particulate matter (PM) emission limit for coal-fired boiler
Unit No. 2 is 0.03 lbs/MMBtu. Since the PM limit for the coal-fired boiler Unit No. 2 from 40 CFR 60,
Subpart Da is more stringent than the PM limit from 326 IAC 6-2-3, pursuant to 326 IAC 6-3-1(c)(5), the
coal-fired boiler Unit No. 2 is exempt from the requirements of 326 IAC 6-2-3.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
(a) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes)
the allowable particulate emission from the coal storage and handling system shall not exceed
71.2 pounds per hour when operating at a process weight rate of 600 tons per hour (1,200,000
pounds per hour).

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

\[
E = 55.0 \cdot P^{0.11} - 40 \quad \text{where} \quad E = \text{rate of emission in pounds per hour; and}
\]
\[
P = \text{process weight rate in tons per hour.}
\]

When the process weight rate exceeds two hundred (200) tons per hour, the maximum allowable
emission may exceed 71.2 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.
The water mist curtain for particulate control shall be in operation and control emissions from the coal storage and handling system (railcar and truck unloading) at all times the coal storage and handling system (railcar and truck unloading) is in operation, unless there is adequate atmospheric precipitation to control emissions or unless the coal is so damp as to control emissions.

(b) Pursuant to 326 IAC 6-3-2(e) (Particulate Emission Limitations for Manufacturing Processes) the allowable particulate emission from the lime storage & handling system and soda ash storage & handling system shall not exceed the amounts determined by the following:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

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

<table>
<thead>
<tr>
<th>Unit Description</th>
<th>Process Weight Rate (ton/hr)</th>
<th>E (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lime Storage &amp; Handling System</td>
<td>21</td>
<td>31.5</td>
</tr>
<tr>
<td>Soda Ash Storage &amp; Handling System</td>
<td>3</td>
<td>8.56</td>
</tr>
</tbody>
</table>

(c) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emissions from Barge Loader system, coal bunker and scale exhausts, and associated dust collector vents shall not exceed the amounts determined by the following:

1) Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

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

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

2) 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:

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

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

3) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emissions may exceed the pounds per hour limitation calculated using the above equation, provided the concentration of particulate in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1000) pounds of gases.

d) Pursuant to 326 IAC 6-3-1.5(2), the maintenance brazing equipment, cutting torches, and soldering and welding equipment are not subject to the requirements of 326 IAC 6-3, since each does not meet the definition of a manufacturing process.

326 IAC 7-1.1 (Sulfur dioxide emission limitations)

(a) The coal-fired boilers Unit No. 1 and Unit No. 2 are subject to the limitations specified in 326 IAC 7-1.1-2. Pursuant to 326 IAC 7-1.1-2(a)(1) (Sulfur Dioxide Emission Limitations), the SO\(_2\) emissions from the Boilers, identified as Unit 1 and Unit 2, each shall not exceed 6.0 pounds per million Btu (lbs/MMBtu).

(b) The one (1) simple-cycle, natural gas-fired combustion turbine ABB No. 3 is subject to the limitations specified in 326 IAC 7-1.1-2. Pursuant to 326 IAC 7-1.1-2(a)(3), Turbine ABB No. 3 shall be limited to 0.5 pounds per million Btu when firing distillate oil.
(c) The one (1) simple-cycle, natural gas-fired combustion turbine ABB No. 4, emergency generators, and fire pump are not subject to the requirements of 326 IAC 7-1.1, because each does not have potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide.

326 IAC 8-3-2 (Cold Cleaner Operations)
The cold cleaning operations are subject to 326 IAC 8-3-2 (Cold Cleaner Operations). This rule applies to cold cleaner type degreasing facilities constructed after January 1, 1980. The parts washer operation at this source were constructed after 1980; therefore, the requirements of 326 IAC 8-3-2 shall apply to these facilities.

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

326 IAC 9 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the units at this source, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-2 (NOx Emissions from Large Affected Units)
Even though Boilers No. 1 and 2 and combustion turbines ABB No. 3 and ABB No. 4 are not cogeneration units and each has a maximum design heat input capacity of greater than 250 MMBtu/hr, the requirements of 326 IAC 10-2 do not apply to these units, because each unit served a generator producing electricity for sale during the applicable time periods listed in 326 IAC 10-2-1(b)(2).

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the units at this source, since they are not blast furnace gas-fired boilers, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

**Compliance Determination and Monitoring Requirements**

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source’s failure to take the appropriate corrective actions within a specific time period.
(a) The Compliance Determination Requirements applicable to this source are as follows:

**Testing Requirements:**

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Control Device</th>
<th>Timeframe for Testing</th>
<th>Pollutant/Parameter</th>
<th>Frequency of Testing</th>
<th>Authority</th>
</tr>
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<tbody>
<tr>
<td>Boiler Unit No. 1</td>
<td>Sorbent Injection System</td>
<td>10/18/2018 (Latest Test Date)</td>
<td>H2SO4</td>
<td>Annually</td>
<td>Joint Stipulation to Modify Consent Decree Civil Action No. IP99-1692 C-M/F, effective December 16, 2015</td>
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<td>10/22/2019 (Proposed Test Date)</td>
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<td>Boiler Unit No. 2</td>
<td>Sorbent Injection System</td>
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<td>Annually</td>
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<td>08/13/2019 (Proposed Test Date)</td>
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**Continuous Emissions Monitoring System (CEMS) and Continuous Opacity Monitoring (COM) Requirements:**

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<tr>
<th>Emission Unit</th>
<th>Type of Continuous Monitor (Pollutant Monitored)</th>
<th>Applicable Rule or Authority</th>
</tr>
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<tr>
<td>Boiler Unit No. 1</td>
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<td>Boiler Unit No. 2</td>
<td>CEMS for PM, SO2, NOX, and either CO2 or O2</td>
<td>326 IAC 3-5 326 IAC 7-1.1 40 CFR 60 (NSPS) 326 IAC 2-2 (BACT)</td>
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<td>ABB CT No. 3</td>
<td>CEMS for NOX and either CO2 or O2</td>
<td>326 IAC 2-2</td>
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<td>ABB CT No. 4</td>
<td>CEMS for CO, NOX and either CO2 or O2</td>
<td>326 IAC 2-2 (BACT)</td>
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(b) The Compliance Monitoring Requirements applicable to this source are as follows:

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<th>Control Device or Emission Unit</th>
<th>Type of Parametric Monitoring</th>
<th>Frequency</th>
<th>Range or Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sorbent injection systems for the coal-fired boilers (Unit No. 1 and Unit No. 2)</td>
<td>Sorbent feed rate</td>
<td>Continuous</td>
<td>Value determined from the most recent compliance stack test</td>
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<tr>
<td>ABB No. 3</td>
<td>Visible Emissions</td>
<td>Daily when combusting fuel oil</td>
<td>Normal-Abnormal</td>
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<tr>
<td>Coal transfer exhaust point, coal bunker and scale exhausts</td>
<td>Visible Emissions</td>
<td>Weekly</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Railcar and truck unloading</td>
<td>Visible Emissions</td>
<td>Daily</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Lime storage and handling system transfer point exhausts and the soda ash storage and handling system transfer point exhausts</td>
<td>Visible Emissions</td>
<td>Daily</td>
<td>Normal-Abnormal</td>
</tr>
<tr>
<td>Soda ash handling exhaust</td>
<td>Visible Emissions</td>
<td>Daily</td>
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<td>Visible Emissions</td>
<td>Weekly</td>
<td>Normal-Abnormal</td>
</tr>
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</table>

These monitoring conditions are necessary because the sorbent injection systems for the coal-fired Boilers Unit No. 1 and Unit No. 2 must operate properly to assure compliance with H2SO4 limits in the

These monitoring conditions are necessary for the turbine ABB No. 3 to assure compliance with the PSD minor limits of 326 IAC 2-2 (Prevention of Significant Deterioration).

These monitoring conditions are necessary for the coal storage and handling system, lime storage and handling system, and fly ash handling system to assure compliance with 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes).

<table>
<thead>
<tr>
<th>Conclusion and Recommendation</th>
</tr>
</thead>
</table>

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on October 4, 2018. Additional information was received on April 26, 2019.

The operation of this electric utility generating station shall be subject to the conditions of the attached proposed Part 70 Operating Permit Renewal No. T129-40544-00010.

The staff recommends to the Commissioner that the Part 70 Operating Permit Renewal be approved.

<table>
<thead>
<tr>
<th>IDEM Contact</th>
</tr>
</thead>
</table>

(a) If you have any questions regarding this permit, please contact Tamara Havics, 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) 232-8219 or (800) 451-6027, and ask for Tamara Havics or (317) 232-8219.

(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 Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens’ Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.
## Appendix A.1: Emissions Calculations

### Company Name:
Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station

### Source Address:
8511 Welborn Road, Mt. Vernon, IN 47620

### Permit Renewal No.:
T129-40544-00010

### Reviewer:
Bharathi Bhattu/Tamara Havics

### Emission Summary

<table>
<thead>
<tr>
<th>Uncontrolled Potential Emissions (tons/yr)</th>
<th>PM</th>
<th>PM-10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>H2SO4</th>
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</thead>
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<td>13,836.18</td>
<td>3,609.44</td>
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<td>59.47</td>
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<td>88.23</td>
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<td>Coal boiler Unit 2</td>
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<tr>
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<td>Startup/Shutdown for Unit 4</td>
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<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>H2SO4</th>
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</thead>
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<tr>
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<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
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<th>H2SO4</th>
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<tr>
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Control efficiency for coal Unit No. 1 using baghouse is 99.80% AP-42 Table 1.1-6
Control efficiency for coal UNIT No. 2 using ESP is 99.20% AP-42 Table 1.1-7
Control efficiency for coal Unit No. 1 & 2 using SCR is 85.00% AP-42 Table 1.1-2
Control efficiency for coal Unit No. 1 &2 using FGD is 90.00% AP-42 9/98 pg 1.1-7 or air Pollution Control Technology Fact Sheet
Flue Gas Desulfurization (FGD)-Wet, Spray dry, and Dry Scrubbers EPA-452/F-03-034
# Appendix A.1: Emissions Calculations

## Emission Summary - HAPs

**Company Name:** Southern Indiana Gas and Electric Company -AB. Brown  
**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620  
**Permit Renewal No.:** T129-40544-00010  
**Reviewer:** Bharathi Bhattu/Tamara Havics

### Uncontrolled Potential Emissions (tons/yr)

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<th></th>
<th>Total HAPs</th>
<th>Single HAP</th>
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<td>Coal boiler Unit 2</td>
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</tr>
<tr>
<td>Coal Handling 1 &amp; 2</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Lime S &amp; H</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Soda Ash Storage</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Emergency Generators</td>
<td>4.38E-03</td>
<td>1.64E-03</td>
</tr>
<tr>
<td>Turbine Unit 3</td>
<td>5.28</td>
<td>3.10</td>
</tr>
<tr>
<td>Turbine Unit 4</td>
<td>4.60</td>
<td>3.56</td>
</tr>
<tr>
<td>Startup/Shutdown for Unit 4</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Firepump</td>
<td>1.36E-03</td>
<td>4.13E-04</td>
</tr>
<tr>
<td>Paved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Unpaved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,430.5</td>
<td>1,206.0</td>
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</tbody>
</table>

### Controlled Potential Emissions (tons/yr)

<table>
<thead>
<tr>
<th></th>
<th>Total HAPs</th>
<th>Single HAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal boiler Unit 1</td>
<td>58.91</td>
<td>19.46</td>
</tr>
<tr>
<td>Coal boiler Unit 2</td>
<td>59.20</td>
<td>19.56</td>
</tr>
<tr>
<td>Coal Handling 1 &amp; 2</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Lime S &amp; H</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Soda Ash Storage</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Emergency Generators</td>
<td>4.38E-03</td>
<td>1.64E-03</td>
</tr>
<tr>
<td>Turbine Unit 3</td>
<td>5.28</td>
<td>3.10</td>
</tr>
<tr>
<td>Turbine Unit 4</td>
<td>4.60</td>
<td>3.56</td>
</tr>
<tr>
<td>Startup/Shutdown for Unit 4</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Firepump</td>
<td>1.36E-03</td>
<td>4.13E-04</td>
</tr>
<tr>
<td>Paved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Unpaved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>128.0</td>
<td>39.0</td>
</tr>
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</table>

### Limited Potential Emissions (tons/yr)

<table>
<thead>
<tr>
<th></th>
<th>Total HAPs</th>
<th>Single HAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal boiler Unit 1</td>
<td>58.91</td>
<td>19.46</td>
</tr>
<tr>
<td>Coal boiler Unit 2</td>
<td>59.20</td>
<td>19.56</td>
</tr>
<tr>
<td>Coal Handling 1 &amp; 2</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Lime S &amp; H</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Soda Ash Storage</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Emergency Generators</td>
<td>4.38E-03</td>
<td>1.64E-03</td>
</tr>
<tr>
<td>Turbine Unit 3</td>
<td>0.32</td>
<td>0.22</td>
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<td>Turbine Unit 4</td>
<td>4.60</td>
<td>3.56</td>
</tr>
<tr>
<td>Startup/Shutdown for Unit 4</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Firepump</td>
<td>1.36E-03</td>
<td>4.13E-04</td>
</tr>
<tr>
<td>Paved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Unpaved Road</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>123.0</td>
<td>39.0</td>
</tr>
</tbody>
</table>
### Appendix A.1: Emission Calculations

#### Coal-Fired Boiler (Unit No. 1)

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station  
**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620  
**Permit Renewal No.:** T129-40544-00010  
**Reviewer:** Bharathi Bhattu/Tamara Havics  

### Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #1 - Fabric Filter (FF)

**Heat Input Capacity (MMBtu/hr)**  
<table>
<thead>
<tr>
<th>Year</th>
<th>MMBtu/hr</th>
<th>Potential Throughput (MMBtu/hr)</th>
<th>Source provided</th>
<th>% Sulfur</th>
<th>Ash %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>2518</td>
<td>1020</td>
<td></td>
<td>4.0</td>
<td>12.00</td>
</tr>
</tbody>
</table>

**Uncontrolled Emission Calculations**

**Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #1 - Fabric Filter (FF)**

### Uncontrolled Coal Emission

<table>
<thead>
<tr>
<th>Heat Content of Coal (MMBtu/ton)</th>
<th>Potential Throughput (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>22 MMBtu/ton</td>
<td>1020</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor (lb/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>120</td>
</tr>
<tr>
<td>PM10</td>
<td>27.6</td>
</tr>
<tr>
<td>PM2.5</td>
<td>7.29</td>
</tr>
<tr>
<td>SO2</td>
<td>152.6</td>
</tr>
<tr>
<td>NOx</td>
<td>11.0</td>
</tr>
<tr>
<td>VOC</td>
<td>0.06</td>
</tr>
<tr>
<td>CO</td>
<td>5.58</td>
</tr>
</tbody>
</table>

**Potential Throughput:**  
Potential Throughput (tons/yr) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

**Potential Emission (tons/yr):**  
Potential Emission (tons/yr) = Potential Throughput (ton/yr) x Emission Factor (lb/ton) / 2,000 lb/ton

### Uncontrolled PTE for Coal

<table>
<thead>
<tr>
<th>Heat Input Capacity</th>
<th>Potential Throughput</th>
</tr>
</thead>
<tbody>
<tr>
<td>2518 MMBtu/hr</td>
<td>1020</td>
</tr>
</tbody>
</table>

### Uncontrolled PTE PQQG = pipeline quality natural gas Boiler Unit #1

<table>
<thead>
<tr>
<th>Emission Factor (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.008</td>
</tr>
</tbody>
</table>

### Uncontrolled Emission Calculations - Natural Gas

**Pollutant**  
- **PM** emission factor is filterable PM only.  
- **PM2.5** emission factor is filterable and condensable PM2.5 combined.  
- **Emission Factors for NOx:** Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32  
- emission factors are available in AP-42, Chapter 1.1 for: pc, bd., dry-bot., wall-fd., resp.  
  - 1-01-002-02, 1-03-002-06 (9/98)

### Methodology

- Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton
- All emission factors are based on normal firing.
- MMBtu = 1,000,000 Btu
- MMCF = 1,000,000 Cubic Feet of Gas

---

1. Coal with Ash content (A) fired PC-fired, dry bottom unit, if A is 12% by weight Ash content, then A = 12; the PM emission factor would be for example PM = 10 x 12 = 120 lb/ton
2. S is weight % sulfur content of coal as fired, if fuel is 1.2% sulfur, then S = 1.2.
3. Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32
5. Methodology
## Appendix A.1: Emission Calculations

### Pulverized Coal, Dry-Bottom, Wall-Fired

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station

**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620

**Permit Renewal No.:** T129-40544-00010

**Reviewer:** Bharathi Bhattu/Tamara Havics

### Emission Calculations

**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620

**Permit Renewal No.:** T129-40544-00010

**Reviewer:** Bharathi Bhattu/Tamara Havics

### Pulverized Coal, Dry-Bottom, Wall-Fired

**Pollutant** | **Coal Emission Factor (lb/ton)*** | **PTE of HAP (tons/year)** | **Natural Gas Emission Factor (lb/MMBtu*** | **Natural Gas PTE of HAP (tons/year)** | **Worst-case HAP (tons/year)** | **Controlled HAPs (tpy)**
--- | --- | --- | --- | --- | --- | ---
Antimony | 1.8E-05 | 0.009 | 2.0E-04 | 0.009 | 0.009 | 0.009
Arsenic | 4.1E-04 | 0.206 | 2.0E-04 | 0.206 | 0.206 | 0.206
Beryllium | 2.1E-05 | 0.051 | 1.9E-05 | 0.051 | 0.051 | 0.051
Bolane | 2.1E-06 | 0.050 | 2.1E-06 | 0.050 | 0.050 | 0.050
Cadmium | 5.1E-05 | 0.026 | 1.1E-03 | 0.026 | 0.211 | 0.211
Chromium (VI) | 2.1E-06 | 0.011 | 3.8E-06 | 0.011 | 0.011 | 0.011
Chromium | 2.1E-06 | 0.014 | 3.8E-06 | 0.014 | 0.014 | 0.014
Cobalt | 2.1E-06 | 0.014 | 3.8E-06 | 0.014 | 0.014 | 0.014
**Total Maximum Heat Input Capacity (MMBtu/hr)** | **2518** | **2518** | **1020** | **21625.2**
**Maximum Coal Input Capacity (tons/hr)** | **114**

### Coal-Fired Boiler (Unit No. 1) - HAPs

**Total Maximum Heat Input Capacity (MMBtu/hr)** | **2518** | **2518** | **1020** | **21625.2**

### Note:

- **Total HAP = Combined HAP air emission value for both coal and PQNG**
- All coal HAPs are used as reported in AP-42 with the exception of the VIHAPs of HCl and HF which are adjusted to controlled values due to the aforementioned co-beneficial removal efficiencies associated with the FGD of 97% and 88%, respectively.

**Methodology**

- **Coal Emission Factor (lb/ton)** = Total Maximum Heat Input (MMBtu/hr) / 22 MMBtu/ton
- **Natural Gas Emission Factor (lb/MMBtu)** = 8.76 lbs/MMBtu
- **Controlled HAPs (tpy)** = Total Maximum Heat Input (MMBtu/hr) / 22 MMBtu/ton * Emission Factor (lb/ton) * 8,760 hrs/yr * 1 ton/2,000 lb

**Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Subbituminous Coal Combustion.**

**SCC 1-01-002-05/21**

**SCC 1-02-002-06/22**

**SCC 1-03-002-06/22**

- **Total HAPs (tpy)**
- **Total HAPs with efficiency removal**
- **Total HAPs with efficiency removal**

**Note:** Total HAP = Combined HAP air emission value for both coal and PQNG

All coal HAPs are used as reported in AP-42 with the exception of the VIHAPs of HCl and HF which are adjusted to controlled values due to the aforementioned co-beneficial removal efficiencies associated with the FGD of 97% and 88%, respectively.
## Limited Coal Emission

<table>
<thead>
<tr>
<th>Heat Input Capacity (MMBtu/hr)</th>
<th>Heat Content of Coal (MMBtu/ton)</th>
<th>Heat Content of Coal (Btu/lb)</th>
<th>Potential Throughput (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2518</td>
<td>22</td>
<td>11000</td>
<td>1,002,622</td>
</tr>
</tbody>
</table>

### Emission Calculations

<table>
<thead>
<tr>
<th>Pollutant (tons per year)</th>
<th>PM*</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2**</th>
<th>NOx**</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/ton</td>
<td>FPM10</td>
<td>CPM</td>
<td>FPM2.5</td>
<td>CPM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.727</td>
<td>0.7</td>
<td>0.06</td>
</tr>
</tbody>
</table>

- **PM limit:** 0.1 pounds per MMBtu of energy input (NSPS 40 CFR 60, Subpart D)
- **SO2 limit:** 0.727 pounds per million Btu (MMBtu) of energy input (Commissioner's Order for Sulfur Dioxide (SO2))
- **NOx limit:** 0.7 pounds per MMBtu of energy input (NSPS 40 CFR 60, Subpart D)

### Limited PQNG Emission

<table>
<thead>
<tr>
<th>Heat Input Capacity of PQNG (MMBtu/hr)</th>
<th>Potential Throughput (MMCF/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2518</td>
<td>21625.2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant (tons per year)</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/10^6 scf</td>
<td>FPM10</td>
<td>CPM</td>
<td>FPM2.5</td>
<td>CPM</td>
<td>5.50</td>
<td>84.00</td>
<td></td>
</tr>
</tbody>
</table>

PM10 = FPM10
PM2.5 = CPM
SO2 = SO2
NOx = NOx
VOC = VOC
CO = CO

PQNG air emission factors for:
- Fabric filter or baghouse
- Laminar Wall fired boiler, 900 mm Btu/hr
- CO in 1-01-006-01-Controlled Nox burners
- VOC = AP-42 Table 1.4-1
- FGD = flue gas desulfurization systems
- NG = 1020 Btu/ft³

### Coal Emission

- **Limited Emission in tons/yr (CO, VOC) = EF (lb/ton)* Heat Input Capacity (MMBtu/hr)/8670 (hr/yr) / 2000 (lb/ton) * heat content Coal (MMBtu/ton)**
- **PQNG**

### PQNG Emission

- **Limited Emission in tons/yr (CO, VOC) = EF/10^6 (lb/ft³) * 1/1020 (ft³/btu) * 10^6 (btu/MMBtu) * Heat Input Cap (MMBtu/hr)/8670 (hr/yr) / 2000 (lb/ton)**
Appendix A.1: Emission Calculations

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station
Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Renewal No.: T129-40544-00010

Reviewer: Bharathi Bhattu/Tamara Havics

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #2 - Electrostatic Precipitator (ESP)

<table>
<thead>
<tr>
<th>Heat Input Capacity (MMBtu/hr)</th>
<th>Heat Content of Coal (MMBtu/ton)</th>
<th>Potential Throughput (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2530</td>
<td></td>
<td>1,007,400</td>
</tr>
</tbody>
</table>

Source provided Weight %

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Coal with Ash content (A)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4.0</td>
<td>12.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>fired PC-fired, dry bottom unit, if A is 12% by weight Ash content, then A = 12; the PM emission factor would be for example PM = 10 * 12 = 120 lb/ton</td>
</tr>
</tbody>
</table>

Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10⁶ Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr

Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f’d., nsps: 1-01-002-02, 1-03-002-06 (9/98)

Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton

Uncontrolled PQNG = pipeline quality natural gas Unit #2

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.9</td>
<td>7.6</td>
<td>7.6</td>
<td>0.6</td>
<td>6.5</td>
<td>5.50</td>
<td>84.0</td>
</tr>
</tbody>
</table>


Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Appendix A.1: Emission Calculations

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station
Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Renewal No.: T129-40544-00010

Reviewer: Bharathi Bhattu/Tamara Havics

### Pulverized Coal, Dry-Bottom, Wall-Fired

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Coal Emission Factor (lb/MMBtu)</th>
<th>Coal PTE HAP (ton/year)</th>
<th>Natural Gas Emission Factor (lb/MMBtu)</th>
<th>Natural Gas PTE HAP (ton/year)</th>
<th>Worstcase HAP (ton/year)</th>
<th>Controlled HAPs (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anhydrite</td>
<td>1.8E-05</td>
<td>0.009</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arsine</td>
<td>1.8E-04</td>
<td>0.009</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Benzo[ghi]perylene</td>
<td>1.30E-06</td>
<td>0.009</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Chlorobenzene</td>
<td>1.70E-05</td>
<td>0.009</td>
<td></td>
<td></td>
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<td></td>
</tr>
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<td>Chloroform</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>Cyanide</td>
<td>2.50E-03</td>
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<td></td>
<td></td>
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<tr>
<td>Dichlorobenzene</td>
<td>2.60E-07</td>
<td>0.000</td>
<td></td>
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<tr>
<td>Dibenzofuran[cd]</td>
<td>1.20E-06</td>
<td>0.000</td>
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<td></td>
</tr>
<tr>
<td>Dimethyl Sulfate</td>
<td>4.80E-05</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>Ethyl Benzene</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Ethyl Chloride</td>
<td>4.20E-06</td>
<td>0.051</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethylene Dichloride</td>
<td>4.00E-05</td>
<td>0.050</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethylene Dichloroformine</td>
<td>1.20E-06</td>
<td>0.001</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluorofluorine</td>
<td>3.00E-06</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>2.40E-04</td>
<td>0.121</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hexane</td>
<td>6.70E-06</td>
<td>0.034</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Isopropylisopropylol</td>
<td>1.50E-05</td>
<td>0.009</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Isopropylol</td>
<td>1.80E-05</td>
<td>0.009</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methyl Acrylate</td>
<td>3.00E-05</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methyl Chloride</td>
<td>5.30E-04</td>
<td>0.067</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methyl Methacrylate</td>
<td>2.00E-05</td>
<td>0.010</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methyl tert Butyl Ether</td>
<td>3.50E-05</td>
<td>0.018</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methyl Chloroform</td>
<td>2.90E-04</td>
<td>0.146</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methylamine</td>
<td>1.20E-05</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Naphthalene</td>
<td>6.10E-04</td>
<td>0.007</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phenol</td>
<td>1.60E-05</td>
<td>0.008</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Propionaldehyde</td>
<td>2.80E-04</td>
<td>0.191</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pyrene</td>
<td>5.00E-06</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Toluene</td>
<td>4.30E-05</td>
<td>0.022</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tetrachloroethylene</td>
<td>2.40E-04</td>
<td>0.121</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| **Total worst efficiency removal** | **39.0** | **20.5** | **59.2** | **712.0** | **Total HAP = Combined HAP air emission value for both coal and PQNG**

All coal HAPs are used as reported in AP-42 with the exception of the VIHAPs of HCl and HF which are adjusted to controlled values due to the aforementioned co-beneficial removal efficiencies associated with the FGD of 97% and 88%, respectively.

Note: Total HAP = Combined HAP air emission value for both coal and PQNG


**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32**
### Appendix A.1: Emission Calculations

#### Coal-Fired Boiler (Unit No. 2) - Limited PTE

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station  
**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620  
**Permit Renewal No.:** T129-40544-00010  
**Reviewer:** Bharathi Bhattu/Tamara Havics

#### Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #2 W/ESP

<table>
<thead>
<tr>
<th>Limited Coal Emission</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Heat Input Capacity (MMBut/hr)</td>
</tr>
<tr>
<td></td>
<td>2530</td>
</tr>
</tbody>
</table>

#### Emission Calculations

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td>Emission Factor in lb/ton</td>
<td>0.02</td>
</tr>
<tr>
<td>Emission Factor in lb/MMBtu</td>
<td>0.02</td>
</tr>
</tbody>
</table>

| Limited Emission in tons/yr | 3.32   |
|                            | 7.646  |
|                            | 6.649  |
|                            | 30.22  |
|                            | 251.85 |

Pursuant to PSD (65) 1355 issued on February 22, 1979, the emission rates from Unit 2 shall not exceed the following:

(a) Particulate matter (PM) - 0.03 pounds per million Btu (MMBtu) of energy input.
(b) Sulfur dioxide - 0.69 pounds per million Btu (MMBtu) of energy input.
(c) Nitrogen oxides - 0.6 pounds per million Btu (MMBtu) of energy input.

Differentiate PM/PM10/PM2.5 calculations: PM emission value is filterable (FPM) only whereas the PM10 & PM2.5 value include both filterable and condensable (CPM) forms (EPA rule convention)

### Coal Fuel air emission factors for PM10 & PM2.5 using Electrostatic Precipitator (ESP)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0201 lb/MMBtu</td>
</tr>
</tbody>
</table>

**Limited PQNG Emission**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0067 lb/MMBtu</td>
</tr>
</tbody>
</table>

#### Limited Coal Emission

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0201 lb/MMBtu</td>
</tr>
</tbody>
</table>

**Limited PQNG Emission**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0067 lb/MMBtu</td>
</tr>
</tbody>
</table>

**Limited Emission in tons/yr (PM, SO2, NOx) = PSD limit (lb/MMBtu) * Heat Input Capacity (MMBut/hr) / 2000 (lb/ton)**

**Limited Emission in tons/yr (PM10, PM2.5) = (FPM EF (lb/MMBtu) + CPM total (lb/MMBtu)) * Heat Input Capacity (MMBut/hr) / 2000 (lb/ton)**

**Coal**


Emission Factors from AP-42, Table 1.1-6 ESP FPM10 = 67% for 10 micron = 0.0201 lb/MMBtu  
Emission Factors from AP-42, Table 1.1-5 Pulverized coal w/ FGD controls CPM total = 0.02 lb/MMBtu

**Limited Emission in tons/yr**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0201 lb/MMBtu</td>
</tr>
</tbody>
</table>

**Limited PQNG Emission**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PM</td>
</tr>
<tr>
<td></td>
<td>FPM10</td>
</tr>
<tr>
<td></td>
<td>0.0067 lb/MMBtu</td>
</tr>
</tbody>
</table>

**Limited Emission in tons/yr (PM10, PM2.5) = (FPM EF (lb/MMBtu) + CPM total (lb/MMBtu)) * Heat Input Capacity (MMBut/hr) / 2000 (lb/ton)**

**Limited Emission in tons/yr (CO, VOC) = EF (lb/ton)* Heat Input Capacity (MMBut/hr) / 2000 (lb/ton) / heat content Coal (MMBtu/ton)**

**Fabric filter or baghouse (FF)**  
**Condensable PM10 = FPM10**  
**FGD = flue gas desulfurization systems**  
**PQNG = pipeline quality natural gas**

**Limited Emission in tons/yr (CO, VOC) = EF (lb/ton)* 1/1020 (lb/MMBtu)^2 * 10^6 (ft^3/MMBtu) / 10^6 (btu/MMBtu) / 1020 (btu/ft^3)**

**Limited Emission in tons/yr (PM, SO2, NOx) = PSD limit (lb/MMBtu) * Heat Input Capacity (MMBut/hr) / 2000 (lb/ton)**
Appendix A: Emission Calculations

Coal Dumping and Handling

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station
Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Renewal No.: T129-40544-00010
Reviewer: Bharathi Bhattu/Tamara Havics

Coal Transfer Emission Factors:
Emissions are generated when the coal is dumped from trucks.

\[
\text{EF (lb/ton)} = k \cdot (0.0032) \cdot (U/5)^{1.3} / (M/2)^{1.4}
\]

where: \( k \) value for:

\[
\begin{array}{c|c|c}
\text{PM} & 1 & 0.35 \\
\text{PM10} & 2.53E-03 & 8.86E-04 \\
\end{array}
\]

- \( U \) value = 10 mph
- \( M \) value = 4.21%
- Material Throughput = 26,280,000 tons/yr

Coal Conveying Emission Factors:

<table>
<thead>
<tr>
<th>Unit Description</th>
<th>Number of Conveyor Units</th>
<th>Max. Capacity (tons/hr/unit)</th>
<th>PM Emission Factor* (lbs/ton)</th>
<th>PM10 Emission Factor* (lbs/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conveyors</td>
<td>2</td>
<td>600.0</td>
<td>1.4E-04</td>
<td>4.6E-05</td>
</tr>
</tbody>
</table>

* Emission factors are from AP-42, Table 11.19.2-2 (08/04).

Since the coal received at this facility has high moisture content (6.9%), the controlled emission factors in AP-42, Table 11.19.2-2 are used in the PTE calculations.

Potential to Emit:

<table>
<thead>
<tr>
<th>Unit</th>
<th>Max Rating (MMBtu/hr)</th>
<th>Coal Spec (Btu/lb)</th>
<th>Max Coal Usage (ton/hr)</th>
<th>Max Coal Usage (ton/yr)</th>
<th>Total Coal Usage (ton/yr)</th>
<th>Storage (90-day)</th>
<th>Max. Throughput (ton/hr)</th>
<th>Coal Usage (ton/yr)</th>
<th>Max. Coal Usage (ton/yr)</th>
<th>Storage Capacity (ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2518</td>
<td>11,000</td>
<td>114.5</td>
<td>1,002,022</td>
<td>1,507,516</td>
<td>185,416</td>
<td>600</td>
<td>3132</td>
<td>1,747,200</td>
<td>700,000</td>
</tr>
<tr>
<td>2</td>
<td>2530</td>
<td>11,000</td>
<td>115.0</td>
<td>1,007,400</td>
<td>1,879,233</td>
<td>186,300</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Coal activity (ton/hr) = 1,747,200

Methodology:

**Coal Conveying**

Max Coal Usage (ton/hr) = Max Rating (MMBtu/hr) * 1,000,000 Btu/MMBtu / Coal Spec (Btu/lb) / 2000 lb/ton

Max Coal Usage (ton/yr) = Max Coal Usage (ton/hr) * 8760 hrs/yr

Coal Usage (ton/hr) = Max Coal Usage (ton/yr) * 75%

Storage (90-day) = Max Coal Usage (ton/yr) * 90 days / 365 days

hr/yr usage = Total Coal Usage (ton/yr) / Max. Throughput (ton/hr)

PTE of PM/PM10 (tons/yr) = Number of Conveyor Units x Max. Capacity (tons/hr/unit) x Emission Factor (lbs/ton) x 8760 hrs/yr x 1 ton/2000 lbs

Coal activity (tph) = Throughput (tph) * 8 hr/day * 7 days/week * 52 wk/yr

326 IAC 6-3-2 Emission limit (lb/hr) = Coefficient * \( \text{PPR} \) (tph) / \( \text{Y} \) - constant

Uncontrolled Emission (tpy) = \( E \) (pph) * 8760 (hr/yr) / 2000 (lbs/ton)

Controlled Emission = (1- control eff) * Uncontrolled Emission (tpy)

**Coal Transfering**

PM EF(lb/ton) = EF (lb/ton) * Maximum Throughput (tons/yr) / 1 ton/2000 lbs

PTE of PM10 (tons/year) = EF (lb/ton) * Maximum Throughput (tons/yr) / 1 ton/2000 lbs
# Appendix A.1: Emission Calculations

## Limestone Material Handling Systems

## Drop Point Calculation

### Company Name:
Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station

### Source Address:
8511 Welborn Road, Mt. Vernon, IN 47620

### Permit Renewal No.:
T129-40544-00010

### Reviewer:
Bharathi Bhattu/Tamara Havics

<p>| | | | |</p>
<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td></td>
<td></td>
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</tbody>
</table>

#### 2 silos: 1 and 2

**Soda ash usage**

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1:1 molar ratio</td>
<td>2,010,022</td>
<td>4</td>
<td>5%</td>
</tr>
<tr>
<td>SO₂ loading (tpy)</td>
<td>160,802</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soda ash MW</td>
<td>105.99</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂ MW</td>
<td>64.062</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soda ash charge (tpy)</td>
<td>266,045</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soda ash loss (%)</td>
<td>10%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soda ash makeup (tpy)</td>
<td>26,605</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soda ash makeup (tph)</td>
<td>3.0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Lime usage**

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1:1 molar ratio</td>
<td>2,010,022</td>
<td>4</td>
<td>5%</td>
</tr>
<tr>
<td>SO₂ loading (tpy)</td>
<td>160,802</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lime MW</td>
<td>56.08</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂ MW</td>
<td>64.062</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lime usage (tpy)</td>
<td>183,689</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lime usage (tph)</td>
<td>21.0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Soda ash storage**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Capacity (tons)</td>
<td>677</td>
<td></td>
</tr>
<tr>
<td>Usage (tph)</td>
<td>3.0</td>
<td></td>
</tr>
<tr>
<td>Retention period (hr)</td>
<td>223</td>
<td></td>
</tr>
</tbody>
</table>

Ongoing delivery via pneumatic tank truck

**Lime storage**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Receiving silos</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Capacity (tons)</td>
<td>5200 (combined)</td>
<td></td>
</tr>
<tr>
<td>Usage (tph)</td>
<td>21.0</td>
<td></td>
</tr>
<tr>
<td>Retention period (hr)</td>
<td>248</td>
<td></td>
</tr>
</tbody>
</table>

Ongoing delivery via truck

**Soda ash storage and handling**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Soda ash truck unloading station</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Soda ash delivery (tons)</td>
<td>675</td>
<td></td>
</tr>
<tr>
<td>Storage tanks (tph)</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Product loss (%)</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td>Product loss (pph)</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>Product loss (tpy)</td>
<td>2.6</td>
<td></td>
</tr>
</tbody>
</table>

**Total emissions**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>pph</td>
<td>0.60</td>
<td></td>
</tr>
<tr>
<td>tpy</td>
<td>2.63</td>
<td></td>
</tr>
</tbody>
</table>

**Lime storage and handling emissions**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Lime usage (tph)</td>
<td>21.0</td>
<td></td>
</tr>
<tr>
<td>Lime usage (tpy)</td>
<td>183,689</td>
<td></td>
</tr>
<tr>
<td>Storage Silo 1 (tons)</td>
<td>2600</td>
<td></td>
</tr>
<tr>
<td>Exhaust rate (cfm)</td>
<td>1500</td>
<td></td>
</tr>
<tr>
<td>Emission control</td>
<td>FF</td>
<td></td>
</tr>
<tr>
<td>Emission loading (gr/dscf)</td>
<td>0.022</td>
<td></td>
</tr>
<tr>
<td>Emission rate (pph)</td>
<td>0.28</td>
<td></td>
</tr>
<tr>
<td>Emission rate (tpy)</td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>Emission rate (gr/dscf)</td>
<td>0.022</td>
<td></td>
</tr>
<tr>
<td>Emission rate (gr/dscf)</td>
<td>0.28</td>
<td></td>
</tr>
<tr>
<td>Emission rate (tpy)</td>
<td>1.2</td>
<td></td>
</tr>
</tbody>
</table>

**Total emissions**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>pph</td>
<td>0.57</td>
<td></td>
</tr>
<tr>
<td>tpy</td>
<td>2.48</td>
<td></td>
</tr>
</tbody>
</table>

### Methodology

Emission rate (pph) = Exhaust rate (cfm) * 60 (min/hr) * Emission loading (gr/dscf) / 7000 (gr/lb)

Emission rate (tpy) = Emission rate (pph) * 8760 (hr/yr) / 2000 (lb/ton)
**Appendix A: Emission Calculations**

**Emergency Generators #1 and #2**

Reciprocating Internal Combustion Engines - Diesel Fuel  
Output Rating (<=600 HP)  
Maximum Input Rate (<=4.2 MMBtu/hr)

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)  
**Address:** AB. Brown Generating Station  
8511 Welborn Road, Mt. Vernon, IN 47620  
**Renewal No:** T129-40544-00010  
**Reviewer:** Bharathi Bhattu/Tamara Havics

<table>
<thead>
<tr>
<th>Facility/Unit</th>
<th>hp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emergency Generator #1</td>
<td>398</td>
</tr>
<tr>
<td>Emergency Generator #2</td>
<td>398</td>
</tr>
<tr>
<td>Emergency Generators total</td>
<td>796</td>
</tr>
</tbody>
</table>

**Emissions calculated based on output rating (hp)**

<table>
<thead>
<tr>
<th>Horsepower (hp)</th>
<th>hp-hr/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>796.0</td>
<td>398,000.0 at 500 hours</td>
</tr>
<tr>
<td></td>
<td>41,392.0 at 52 hours</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>directPM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th><strong>see below</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/hp-hr</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.00205</td>
<td>0.0310</td>
<td>0.00250</td>
<td>0.00668</td>
<td></td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>0.44</td>
<td>0.44</td>
<td>0.44</td>
<td>0.41</td>
<td>6.17</td>
<td>0.50</td>
<td>1.33</td>
<td>at 500 hours</td>
</tr>
<tr>
<td><strong>PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Methodology**

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.  
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]  
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

**Hazardous Air Pollutants (HAPs)**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Benzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>Formaldehyde</th>
<th>Acetaldehyde</th>
<th>Acrolein</th>
<th>Total PAH HAPs***</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/hp-hr****</td>
<td>6.53E-06</td>
<td>2.98E-06</td>
<td>2.00E-06</td>
<td>8.26E-06</td>
<td>5.37E-07</td>
<td>6.48E-07</td>
<td>1.18E-06</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>1.30E-03</td>
<td>5.70E-04</td>
<td>3.97E-04</td>
<td>1.64E-03</td>
<td>1.07E-04</td>
<td>1.29E-04</td>
<td>2.34E-04</td>
</tr>
<tr>
<td>Potential Emission of Total HAPs (tons/yr)</td>
<td>4.38E-03</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)  
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7.000 Btu/hp-hr (AP-42 Table 3.3-1).
### Natural Gas-Fired Turbine

#### Appendix A.1: Emission Calculations

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station  
**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620  
**Permit Renewal No.:** T129-40544-00010  
**Reviewer:** Bharathi Bhattu/Tamara Havics

#### Natural Gas-Fired Turbine

**ABB CT Unit No. 3**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>EF (lb/MM Btu)</th>
<th>pH</th>
<th>Unrestricted</th>
<th>Restricted</th>
<th>Permit</th>
</tr>
</thead>
<tbody>
<tr>
<td>As</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.02</td>
<td>N/A</td>
</tr>
<tr>
<td>Be</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Cd</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Cr</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.01</td>
<td>N/A</td>
</tr>
<tr>
<td>Pb</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Mn</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Hg</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Ni</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
<tr>
<td>Se</td>
<td>NR</td>
<td>0.00</td>
<td>N/A</td>
<td>0.00</td>
<td>N/A</td>
</tr>
</tbody>
</table>

#### HAPs

**Organic**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>EF (lb/MM Btu)</th>
<th>pH</th>
<th>Unrestricted</th>
<th>Restricted</th>
<th>Permit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acetaldehyde</td>
<td>0.000</td>
<td>NR</td>
<td>0.036</td>
<td>N/A</td>
<td>0.16</td>
</tr>
<tr>
<td>Acrolein</td>
<td>0.000</td>
<td>NR</td>
<td>0.006</td>
<td>N/A</td>
<td>0.03</td>
</tr>
<tr>
<td>Benzene</td>
<td>0.000</td>
<td>0.00</td>
<td>0.011</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>1,4-Butadiene</td>
<td>0.000</td>
<td>0.00</td>
<td>0.001</td>
<td>0.03</td>
<td>0.00</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>0.000</td>
<td>NR</td>
<td>0.029</td>
<td>N/A</td>
<td>0.13</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>0.001</td>
<td>0.00</td>
<td>0.637</td>
<td>0.25</td>
<td>0.29</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>0.000</td>
<td>0.00</td>
<td>0.001</td>
<td>0.03</td>
<td>0.01</td>
</tr>
<tr>
<td>Propylene oxide</td>
<td>0.000</td>
<td>0.00</td>
<td>0.002</td>
<td>0.04</td>
<td>0.01</td>
</tr>
<tr>
<td>Toluene</td>
<td>0.000</td>
<td>NR</td>
<td>0.052</td>
<td>N/A</td>
<td>0.23</td>
</tr>
</tbody>
</table>

Potential Emissions (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/2000 lbs

Guaranteed max emissions in tons/yr are hourly max emissions x 8760 hrs/yr x 1 ton/2000 lbs.

PM-10 emission factor and guaranteed emissions are total of condensable and filterable emissions.

*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

Methodology

Sulfur content is maximum allowable; actual data from gas supplier shows 0.00020 to 0.00035 percent by weight.

* From AP-42, Section 3.1 Tables 3.1-1 (uncontrolled and lean-premix values), 3.1-2a, and 3.1-3, updated 4/00; and August 21, 2001, Sims Roy memo.

** Methodology **

Required (lb/hr) = EF (lb/MM Btu) x Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/2000 lbs

Unrestricted (tpy) = Unrestricted (lb/hr) x 8760/2000

Notes: Potential HAPs emissions included for information only.

The AP-42 factors for NOx (lean-premix), CO (lean-premix), VOC, and some of the HAPs have a "D" rating, which indicates that they are only expected to provide an order-of-magnitude value.

Unrestricted (tpy) = EF (lb/MM Btu) x Heat Input Capacity (MMBtu/hr) x emission factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/2000 lbs

Notes:

*With Tennessee for N2O emission factor and Tennessee for N2O emissions.*
Appendix A.1: Emission Calculations
Natural Gas-Fired Turbine, Dry-Low-NOx burners

<table>
<thead>
<tr>
<th>Company Name:</th>
<th>Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source Address:</td>
<td>8511 Welborn Road, Mt. Vernon, IN 47620</td>
</tr>
<tr>
<td>Permit Renewal No.:</td>
<td>T129-40544-00010</td>
</tr>
<tr>
<td>Reviewer:</td>
<td>Bharathi Bhattu/Tamara Havics</td>
</tr>
</tbody>
</table>

**Simple Cycle Operation**
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factor</th>
<th>lb/MMBtu</th>
<th>PTE/CT</th>
<th>PTE</th>
<th>Total PTE</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>0.0271</td>
<td>31.00</td>
<td>132.06</td>
<td>73.06</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>0.0454</td>
<td>52.00</td>
<td>227.76</td>
<td>227.76</td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>0.0015</td>
<td>1.70</td>
<td>7.45</td>
<td>7.45</td>
<td></td>
</tr>
<tr>
<td>SO2</td>
<td>0.0034</td>
<td>3.90</td>
<td>17.06</td>
<td>17.06</td>
<td></td>
</tr>
<tr>
<td>PM10</td>
<td>0.0019</td>
<td>9.54</td>
<td>9.54</td>
<td>9.54</td>
<td></td>
</tr>
<tr>
<td>PM2.5</td>
<td>0.0044</td>
<td>5.00</td>
<td>21.90</td>
<td>21.90</td>
<td></td>
</tr>
</tbody>
</table>

* Emission factors are vendor provided data
** PM emission is PM filterable from AP42 Table 3.1-2a
Calculations are based on Normal Operation + Startup/Shutdown = 8760 hrs/yr

```
EF (lb/MMBtu)  #/hr  #/day  tons/mo  tpy
Acetaldehyde    4.00E-05  4.58E-02  1.10E+00  1.65E-02  0.20
Acrolein       6.49E-05  7.33E-03  1.79E-01  2.30E-03  0.03
Benzene        1.20E-05  1.37E-02  3.30E-01  4.30E-03  0.06
1,3-Butadiene  9.60E-05  1.10E-03  2.64E-02  3.40E-04  0.00
Ethylene       3.20E-05  3.67E-02  8.89E-01  1.10E-02  0.16
Naphthalene   1.30E-04  1.49E-01  3.57E-00  4.70E-02  0.01
Propylene oxide 5.80E-04  6.65E-02  1.59E+00  2.10E-02  0.29
Toluene         1.30E-04  1.49E-01  3.57E+00  4.70E-02  0.01
Xylenes       6.40E-05  7.33E-02  1.79E-01  2.30E-02  0.32
POM            2.20E-06  2.52E-03  6.05E-02  7.90E-04  0.01
As             N/A       N/A     N/A     N/A     N/A
Be             N/A       N/A     N/A     N/A     N/A
Cd             N/A       N/A     N/A     N/A     N/A
Cr             N/A       N/A     N/A     N/A     N/A
Pb             N/A       N/A     N/A     N/A     N/A
Sb             N/A       N/A     N/A     N/A     N/A
Se             N/A       N/A     N/A     N/A     N/A
Total HAP     1.1       25.3    3.87E-01  4.6
```

* From AP-42, Section 3.1 Tables 3.1-1 (uncontrolled and lean-premix values), 3.1-2a, and 3.1-3, updated 4/00; and August 21, 2001
Unrestricted (lb/hr) = EF (lb/MMBtu) * Heat Input Capacity(lb/MMBtu)
Unrestricted (tpy) = Unrestricted (lb/hr) * 8760/2000
Appendix A.1: Emission Calculations
Natural Gas-Fired Turbine, Dry-Low-NOx burners
ABB CT Unit No.4 - Startup/Shutdown

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station
Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Renewal No.: T129-40544-00010
Reviewer: Bharathi Bhattu/Tamara Havics

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max number of startups/shutdown for natural gas per year: 240

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>*Startup Emission (lb/startup)</th>
<th>*Shutdown Emission (lb/shutdown)</th>
<th>Emission Rate/Turbine (tons/yr)</th>
<th>Total Emission Rate (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td>20.7</td>
<td>11</td>
<td>3.80</td>
<td>3.80</td>
</tr>
<tr>
<td>CO</td>
<td>65.5</td>
<td>58.9</td>
<td>14.93</td>
<td>14.93</td>
</tr>
</tbody>
</table>

* Source provided

Emission Rate/Turbine (tpy) =
(Startup Emission (lb/startup)* # of times NG Startup/shutdown /yr) + (Shutdown Emission (lb/shutdown * # of times NG Startup/shutdown /yr))/2000

Total Emission Rate (tons/yr) = Emission Rate/Turbine (tpy)

NOx emissions from ABB No. 4 stack shall be less than 36 pounds per event.
CO emissions from ABB No. 4 stack shall be less than 65 pounds per event
Appendix A.1: Emission Calculations

Reciprocating Internal Combustion Engines - Diesel Fuel

Output Rating (<600 HP)

Maximum Input Rate (<4.2 MMBtu/hr)

Fire Pump

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB, Brown Generating Station

Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620

Permit Renewal No.: T129-40544-00010

Reviewer: Bharathi Bhattu/Tamara Havics

<table>
<thead>
<tr>
<th>Emissions calculated based on output rating (hp)</th>
<th>Diesel Emergency fire pump</th>
<th>200 hp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output Horsepower Rating (hp)</td>
<td>200.0</td>
<td></td>
</tr>
<tr>
<td>Maximum Hours Operated per Year</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td>Potential Throughput (hp-hr/yr)</td>
<td>100,000</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM*</th>
<th>PM10*</th>
<th>direct PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/hp-hr</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
<td>0.0022</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>0.11</td>
<td>0.11</td>
<td>0.11</td>
<td>0.10</td>
<td>1.55</td>
<td>0.13</td>
<td>0.33</td>
</tr>
</tbody>
</table>

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Benzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>1,3-Butadiene</th>
<th>Formaldehyde</th>
<th>Acetaldehyde</th>
<th>Acrolein</th>
<th>Total PAH HAPs***</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor in lb/hp-hr****</td>
<td>6.53E-06</td>
<td>2.86E-06</td>
<td>2.00E-06</td>
<td>2.74E-07</td>
<td>8.26E-06</td>
<td>5.37E-06</td>
<td>6.48E-07</td>
<td>1.18E-06</td>
</tr>
<tr>
<td>Potential Emission in tons/yr</td>
<td>3.27E-04</td>
<td>1.43E-04</td>
<td>9.98E-05</td>
<td>1.37E-05</td>
<td>4.13E-04</td>
<td>2.68E-04</td>
<td>3.24E-05</td>
<td>5.88E-05</td>
</tr>
</tbody>
</table>

***PAH = Polycyclic Aromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

<table>
<thead>
<tr>
<th>Potential Emission of Total HAPs (tons/yr)</th>
<th>1.36E-03</th>
</tr>
</thead>
<tbody>
<tr>
<td>Highest single HAP (tons/yr)</td>
<td>4.13E-04</td>
</tr>
</tbody>
</table>
Appendix A.1: Emission Calculations
Lime/Soda Ash Trucks on Paved Roads
Unit 1 and Unit 2 FGD Systems
Paved Haul Road Calculation

Company Name: Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station
Source Address: 8511 Welborn Road, Mt. Vernon, IN 47620
Permit Renewal No.: T129-40544-00010
Reviewer: Bharathi Bhattu/Tamara Havics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Units</th>
<th>Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Truck Travel Distance (Round Trip)</td>
<td>0.4</td>
<td>miles</td>
<td>Paved road length from gate to silo - 1000 feet estimated</td>
</tr>
<tr>
<td>Empty Limestone Truck Weight</td>
<td>15</td>
<td>tons</td>
<td>Use 30,000 lb</td>
</tr>
<tr>
<td>Loaded Limestone Truck Weight</td>
<td>40</td>
<td>tons</td>
<td>Use 25 Tons/Truck</td>
</tr>
<tr>
<td>Mean Vehicle Weight (W)</td>
<td>28</td>
<td>tons</td>
<td>= (40+15)/2</td>
</tr>
<tr>
<td>Paved Road Silt Loading (sL)</td>
<td>9.7</td>
<td>g/m2</td>
<td>AP-42; Table 13.2.1-3; Irons and Steel Production</td>
</tr>
<tr>
<td>Days with &gt; 0.01&quot; of precipitation (p)</td>
<td>120.0</td>
<td>days</td>
<td>AP-42; Figure 13.2.1-2</td>
</tr>
<tr>
<td>PM particle size factor (k)</td>
<td>0.011</td>
<td>lb/VMT</td>
<td>AP-42; Table 13.2.1-1</td>
</tr>
<tr>
<td>PM10 particle size factor (k)</td>
<td>0.0022</td>
<td>lb/VMT</td>
<td>AP-42; Table 13.2.1-1</td>
</tr>
<tr>
<td>PM2.5 particle size factor (k)</td>
<td>0.00054</td>
<td>lb/VMT</td>
<td>AP-42; Table 13.2.1-1</td>
</tr>
<tr>
<td>Uncontrolled PM Emissions Factor</td>
<td>2.35</td>
<td>lb/VMT</td>
<td>AP-42, Ch. 13.2.1, Eqn. 2</td>
</tr>
<tr>
<td>Uncontrolled PM10 Emissions Factor</td>
<td>0.47</td>
<td>lb/VMT</td>
<td>AP-42, Ch. 13.2.1, Eqn. 2</td>
</tr>
<tr>
<td>Uncontrolled PM2.5 Emissions Factor</td>
<td>0.12</td>
<td>lb/VMT</td>
<td>AP-42, Ch. 13.2.1, Eqn. 2</td>
</tr>
</tbody>
</table>

Notes:
1. The revised EPA AP-42 Chapter 13.2.1 (Jan 2011) is used for this calculation:
   http://www.epa.gov/ttn/chief/ap42/ch13/index.html
2. For the purpose of this calculation, limestone truck roads are considered a new emissions unit.

PM/PM10/PM2.5 uncontrolled (tpy) = Uncontrolled PM Emissions Factor (lb/VMT) * miles per year /2000 (lb/ton)
PM10/PM2.5 controlled = (1-control eff) * PM/PM10/PM2.5 uncontrolled (tpy)
## Appendix A: Emission Calculations
### Gypsum Trucks on Unpaved Roads
#### Unit 1 and Unit 2 FGD Systems

**Unpaved Haul Road Calculation**

**Company Name:** Southern Indiana Gas and Electric Company (SIGECO)-AB. Brown Generating Station

**Source Address:** 8511 Welborn Road, Mt. Vernon, IN 47620

**Permit Renewal No.:** T129-40544-00010

**Reviewer:** Bharathi Bhattu/Tamara Havics

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Units</th>
<th>Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Truck Travel Distance (Round Trip)</td>
<td>1.6</td>
<td>miles</td>
<td>Road distance from SO2 dewatering to storage pile 0.8 miles</td>
</tr>
<tr>
<td>Empty Gypsum Truck Weight</td>
<td>15</td>
<td>tons</td>
<td>Use 30,000 lb</td>
</tr>
<tr>
<td>Loaded Gypsum Truck Weight</td>
<td>40</td>
<td>tons</td>
<td>Use 25 Tons/Truck</td>
</tr>
<tr>
<td>Mean Vehicle Weight (W)</td>
<td>28</td>
<td>tons</td>
<td>=((40+15)/2)</td>
</tr>
<tr>
<td>Silt Content (s)</td>
<td>4.8</td>
<td>%</td>
<td>AP-42 Table 13.2.2-1 Sand and Gravel Processing: mean value</td>
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<tr>
<td>Days with &gt; 0.01&quot; of precipitation (p)</td>
<td>120</td>
<td>days</td>
<td>AP-42; Figure 13.2.2-1: Draft</td>
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<tr>
<td>PM particle size factor (k)</td>
<td>4.0</td>
<td>lb/VMT</td>
<td>AP-42; Table 13.2.2-2; Draft</td>
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<tr>
<td>PM10 particle size factor (k)</td>
<td>1.5</td>
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<td>PM2.5 particle size factor (k)</td>
<td>0.15</td>
<td>lb/VMT</td>
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<td>Uncontrolled PM Emissions Factor</td>
<td>4.69</td>
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<td>Uncontrolled PM10 Emissions Factor</td>
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<td>Uncontrolled PM2.5 Emissions Factor</td>
<td>0.14</td>
<td>lb/VMT</td>
<td>AP-42, Ch. 13.2.1, Eqn. 1; Draft</td>
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</table>

### Waste product
- Calcium sulfite/sulfate
  - Dewatered to 65% solids

### Quantity
- SO2 loading: 160,800
- SO2 control: 90%
- SO2 net loading: 144,720
- SO2 MW: 64,062
- Calcium sulfite/sulfate hydrate MW: 137.75
- Dry product (tpy): 311,186
- Wet product (tpy): 478,747

### Deliveries
- Delivery truck is 40-ton truck at 15-ton empty and 25-ton load

### Emissions
- PM/PM10/PM2.5 uncontrolled (tpy) = Uncontrolled PM Emissions Factor (lb/VMT) * miles per year /2000 (lb/ton)
- PM/PM10/PM2.5 controlled = (1-control eff) * PM/PM10/PM2.5 uncontrolled (tpy)

| Notes:                                                                                   |
| PM/PM10/PM2.5 uncontrolled (tpy) = Uncontrolled PM Emissions Factor (lb/VMT) * miles per year /2000 (lb/ton) |
| PM/PM10/PM2.5 controlled = (1-control eff) * PM/PM10/PM2.5 uncontrolled (tpy)             |

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<tr>
<th>Control measure</th>
<th>Emissions</th>
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</thead>
<tbody>
<tr>
<td>Fugitive dust control</td>
<td>PM uncontrolled (tpy): 71.91</td>
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<tr>
<td>Watering</td>
<td>PM10 uncontrolled (tpy): 22.01</td>
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<tr>
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<td>PM2.5 uncontrolled (tpy): 2.20</td>
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<td>PM controlled (tpy): 7.15</td>
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<td></td>
<td>PM10 controlled (tpy): 2.20</td>
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<td></td>
<td>PM2.5 controlled (tpy): 0.22</td>
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</tbody>
</table>
October 23, 2019

Angela Casbon-Scheller
Sigeco AB Brown Generating Station
PO Box 209
Evansville, IN 47702

Re: Public Notice
Sigeco AB Brown Generating Station
Permit Level: Title V Renewal
Permit Number: 129-40544-00010

Dear Mrs Casbon-Scheller:

Enclosed is a copy of your draft Title V Renewal, Technical Support Document, emission calculations, and the Public Notice.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: [https://www.in.gov/idem/5474.htm](https://www.in.gov/idem/5474.htm)

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Alexandrian Public Library, 115 West 5th in Mt. Vernon, IN 47620. 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 Tamara Havics, 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 2-8219 or dial (317) 232-8219.

Sincerely,

Ashley Estes

Ashley Estes
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter 4/12/19
October 23, 2019

To: Alexandrian Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: Important Information to Display Regarding a Public Notice for an Air Permit

Applicant Name: SIGECO AB Brown Generating Station
Permit Number: 129-40544-00010

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. Please make this information readily available until you receive a copy of the final package.

If you have any questions concerning this public review process, please contact Joanne Smiddle-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library updated 4/2019
Notice of Public Comment

October 23, 2019
SIGECO AB Brown Generating Station
129-40544-00010

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has posted on IDEM’s Public Notice website at https://www.in.gov/idem/5474.htm.

The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana’s Air Permitting Program.

Please Note: If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.
Mail Code 61-53

**Name and address of Sender**

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<th>Handing Charges</th>
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<th>S.H. Fee</th>
<th>Rest. Del. Fee</th>
<th>Remarks</th>
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<td>Angela Casbon-Scheller Sigeco AB Brown South Indiana Gas &amp; Electric Compa PO Box 209 Evansville IN 47702 (Source CAATS)</td>
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<td>Mr. Chuck Polage C F Industries RR 5 Hwy 69 South, P.O. Box 645 Mount Vernon IN 47620 (Affected Party)</td>
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<td>Posey County Commissioners County Courthouse, 126 E. 3rd Street Mount Vernon IN 47620 (Local Official)</td>
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<td>Posey County Health Department 126 E. 3rd St, Coliseum Bldg Mount Vernon IN 47620-1811 (Health Department)</td>
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<td>Mount Vernon City Council and Mayors Office 520 Main Street Mount Vernon IN 47620 (Local Official)</td>
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<td>Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 (Affected Party)</td>
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<td>Mr. Don Mottley Save Our Rivers 6222 Yankeetown Hwy Boonville IN 47601 (Affected Party)</td>
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<td>Mrs. Connie Parkinson 510 Western Hills Dr. Mt. Vernon IN 47620 (Affected Party)</td>
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<td>Juanita Burton 7911 W. Franklin Road Evansville IN 47712 (Affected Party)</td>
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<td>David Boggs 216 Western Hills Dr Mt Vernon IN 47620 (Affected Party)</td>
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Mail Code 61-53

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<th>Type of Mail: CERTIFICATE OF MAILING ONLY</th>
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